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1986 RELIABILITY REVIEW

A REVIEW OF BULK POWER SYSTEM RELIABILITY IN NORTH AMERICA

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

North American Electric Reliability Council

ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interpool Network

MAPP
Mid-continent Area Power Pool

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WSCC
Western Systems Coordinating Council

AFFILIATE

ASCC
Alaska Systems Coordinating Council

The North American Electric Reliability Council (NERC) was formed by the electric utility industry in 1968 to promote the RELIABILITY of bulk power supply in the electric utility systems of North America. NERC consists of nine Regional Reliability Councils and one affiliate encompassing virtually all of the power systems in the United States and Canada.

RELIABILITY in a bulk power electric system is the degree to which the performance of the elements of that system results in power being delivered to consumers within accepted standards and in the amount desired. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer service.

Bulk power electric system reliability can be addressed by considering two basic and functional aspects of the bulk power system—adequacy and security.

ADEQUACY is the ability of the bulk power electric system to supply the aggregate electrical power and energy requirements of the consumers at all times, taking into account scheduled and unscheduled outages of system components.

SECURITY is the ability of the bulk power electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

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1986 Reliability Review

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Executive Summary

The Council's 1986 Review finds the future electric supply and demand picture marked by uncertainty.

While utilities have developed adequate electric supply plans, many of these plans are at risk. A leading concern of the Council is the uncertainty of the electric demand forecast which assumes demands will be reduced by load management, conservation and customer-owned generation. Of equal concern are the supply plans which rely heavily on additional non-utility generation, life-extension programs for aging generating units, and the purchase of large amounts of capacity from other utilities.

Future electric reliability will depend on resolving many issues and impediments. The major concerns of the Council are:

- *The combined electric supply plans of utilities can support annual demand growths of 2.2% in the United States and 2.8% in Canada. There is an 80% probability that annual demand growths will range from -0.2% to 4.4%.*
- *Over 13% of the total capacity additions needed in the next 10 years are coal-fired units which are not yet under construction. Since it takes 8 to 10 years to build a large coal plant, commitments must be made now to assure completion of those units needed in the 1990's.*
- *Non-utility generation makes up 11% of the capacity additions in the United States. However, the operators of most of these facilities do not have the same obligations as utilities to continuing operations and electric reliability. Additionally, most will burn natural gas, a fuel vulnerable to curtailments during cold weather when electric demands are high.*
- *The average age of generating units in the United States will increase to 26 years by 1995 compared to 17 years in 1985 and 11 years in 1975. Many utilities have implemented extensive maintenance and life-extension programs in an attempt to maintain the reliability of their older generators. The results appear to be promising but have yet to be demonstrated over the long-term.*
- *Transmission use will continue to increase, loading many lines to their reliability limits for extended periods. However, utilities are finding it increasingly difficult to expand their transmission systems to meet these increased needs due to uncertainty about future benefits, lengthy licensing processes, and conflicting jurisdictions.*
- *In 1985, purchases and sales of energy between utilities represented 20% of the energy delivered to customers. Increasing these purchases significantly in the future will be precluded unless the impediments to building transmission can be overcome.*
- *The risks of large financial commitments are discouraging utilities from building generation and transmission projects even when the need is evident.*
- *Legislative issues can impact greatly on the adequacy of our future electric supplies. For example, during the next 10 years, over 50% of all electricity in the United States will come from coal. Should electric plants that burn coal be required to meet stricter emission limits, customers in some areas could face extreme shortages of electricity.*

Historically, North America has been served by a highly reliable electric system. That system will be stressed in the years ahead as utilities adjust to non-utility generation, fluctuating energy prices, increasing competition, and less control of their plans and operations. To meet these challenges, utilities will need to keep existing units in operation, keep construction on schedule, work with regulators to shorten lead times for new facilities and strive for effective load management and conservation programs.

Unprecedented cooperation among industry, government and customers will be essential in the decade ahead if we are to protect the reliability of our vitally important electric supply.

Foreword

About the Council

The North American Electric Reliability Council was formed by the electric utility industry in 1968 to promote the RELIABILITY of bulk power supply in the electric utility systems in North America. The Council consists of nine Regional Reliability Councils and one Affiliate encompassing virtually all the power systems in the United States and Canada, and the portion of the Mexican system (Comision Federal de Electricidad) which is interconnected with California.

The governing body of the Council is its Board of Trustees, consisting of two representatives from each Regional Council, plus such additional representatives as prescribed in the By-Laws. There must always be at least one representative on the Board from a Canadian utility system and at least two utility representatives from each segment of the electric utility industry: investor-owned, Federal, rural electric cooperative, and state municipal.

Meetings of the Board are attended by observers from the United States Department of Energy, United States Federal Energy Regulatory Commission, Canadian National Energy Board, Edison Electric Institute, American Public Power Association and National Rural Electric Cooperative Association.

Foreword

About this Report

In October 1970, the North American Electric Reliability Council's Board of Trustees created the Interregional Review Subcommittee to review, on a continuing basis, the overall reliability of the North American bulk power systems as existing and planned among and within the Regional Reliability Councils.

This 1986 Review presents:

- *The Subcommittee's assessment of reliability through 1995*
- *Discussion of the key factors and issues affecting the future of electric power supply, and*
- *Detailed region-by-region assessments of reliability, including discussion of those issues of specific regional concern*

In preparing this report, the Subcommittee interviewed representatives of selected regions, reviewed detailed self-assessments prepared by each of the nine Regional Reliability Councils, reviewed the forecasts made by the utilities and the bandwidths around those forecasts, appraised utility plans and commitments for future bulk power system facilities, and assessed the potential effect of legislation, regulations and governmental policies on future reliability. This report is the culmination of these efforts and reflects the expertise, judgment, and interpretations of the Subcommittee members. The conclusions found in the report are based on current demand and capability projections and on the individual regional assessments.

Unless otherwise noted, the data presented in the graphs and tables in this report have been submitted by the Regional Reliability Councils and reflect conditions as of January 1, 1986. Some data have been extracted from the April 1, 1986 Coordinated Bulk Power Supply Program (IE-411) Reports submitted to the United States Department of Energy (DOE) by each Regional Reliability Council and other data from submittals made directly to the Council. Detailed data and information on projected peak demand, energy requirements, generating capability and fossil fuel requirements are presented in a companion report by the North American Electric Reliability Council — "Electric Power Supply & Demand, 1986-1995."

Loads and Resources

Peak Demand and Energy

The long-term electric peak demand forecast for the United States is essentially the same as was projected the past two years, while the annual energy for load is projected to be slightly lower. In contrast, Canada's long-term peak demand and annual energy projections are both slightly higher than the last two forecasts.

After more than a decade of lowering peak demand and energy forecasts each year, utility forecasts have stabilized over the past three years.

High and low bands around the base 10-year forecasts for the United States and Canada illustrate the uncertainty inherent in the forecasting process.

Recent Experience

The electrical energy generated by U.S. utilities in 1985 exceeded 1984 generation by 2.2% and matched the 1985 forecast. In Canada, 1985 electrical energy exceeded 1984 electrical energy by 5.4% and exceeded the forecast by 2.9%. Table I shows peak demand and electrical energy comparisons for the United States and Canada. Summer peak demand for the United States in 1985 was 2.1% greater than 1984 but about 1% less than forecast. In Canada, winter peak demand was 5.5% above 1984 and 3.2% greater than forecast.

As shown in Figure I, the growth rate of electricity consumption has moderated since the economic recovery experienced in late 1983 and the first six months of 1984. However, the electric energy requirements continue to show an increase. For the 12-month period ending May 1986, net energy for load was above the comparable period one year ago by 1.1% in the United States and 4.0% in Canada.

1986-1995 Forecast

NERC's aggregated peak demand and energy projections over the 1986-1995 period are summarized in Table 2 for the United States, Canada and a small portion of Mexico. The United States is decidedly summer peaking but with a winter peak demand growing at a slightly faster rate than the summer

Figure 1

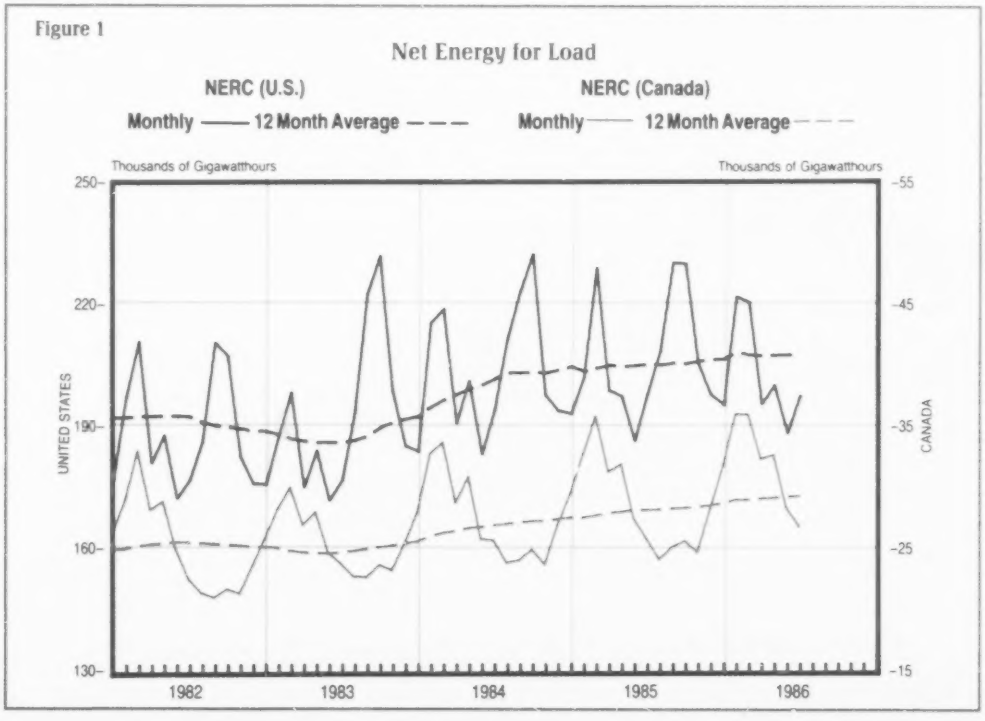


Table 1 — 1985 Actual Peak Demand and Energy Experience					
	1984 Actual	1985 Actual	Actual Change %	1985 Forecast	Actual vs Forecast %
NERC — U.S.					
Summer Peak Demand (Thousands of MW)	451.2	**460.5**	2.1	465.1	-1.0
Winter Peak Demand (Thousands of MW)	436.3	**428.7**	-1.7	422.9	1.4
Annual Energy (Millions of MWh)	2445.6	**2499.2**	2.2	2499.4	-0.01
NERC — Canada[a]					
Summer Peak Demand (Thousands of MW)	42.3	**43.9**	3.9	43.8	0.3
Winter Peak Demand (Thousands of MW)	59.4	**62.7**	5.5	60.8	3.2
Annual Energy (Millions of MWh)	320.6	**338.0**	5.4	328.6	2.9

[a]Excludes Nova Scotia

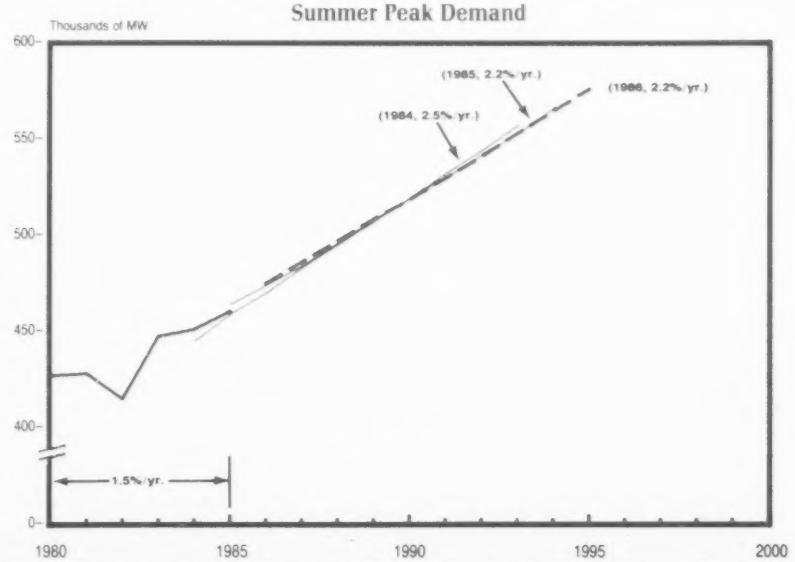
Table 2 — 1986-1995 Forecast of Peak Demand and Energy				
	NERC U.S.	NERC Canada[a]	NERC Mexico[b]	NERC Total
Summer Peak Demand (Thousands of MW)				
1986	475	47	0.6	523
1995	577	61	1.2	639
Average Growth (%/yr)	2.2	3.0	7.1	2.3
Winter Peak Demand (Thousands of MW)				
1986/87	435	65	0.4	500
1995/96	533	83	0.8	618
Average Growth (%/yr)	2.3	2.8	7.1	2.4
Annual Energy (Millions of MWh)				
1986	2,525	350	3.0	2,878
1995	3,103	462	5.6	3,571
Average Growth (%/yr)	2.3	3.1	7.3	2.4

[a]Includes Nova Scotia [b]Northern portion of Baja California, Mexico only

Figure 2

NERC (U.S.) Comparison of Recent Forecasts

Summer Peak Demand



demand. In direct contrast, Canada, a winter peaking region, has a summer peak demand rate of growth higher than its winter peak growth rate.

The projected 1986-1995 growth rates for annual energy are higher than the growth rates for peak demand in all three countries represented in NERC. A continuation of this trend will result in increased annual system load factors and more effective use of facilities but will complicate the scheduling for maintenance of facilities.

Load management and conservation programs are factored into the forecast of many utilities. These programs are expected to restrain future load growth.

Comparisons of Recent Forecasts

Table 3 shows a comparison of average annual growth rates for the current forecast and the two prior years' forecasts. After a number of years during which utilities reduced their peak

Figure 3

NERC (Canada) Comparison of Recent Forecasts[a]

Winter Peak Demand

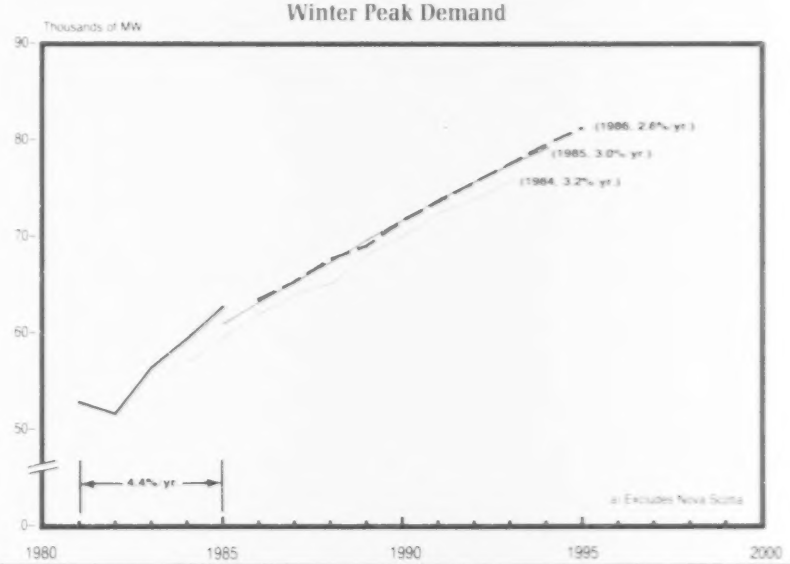


Figure 4

NERC (U.S.) Comparison of Recent Forecasts

Net Energy for Load

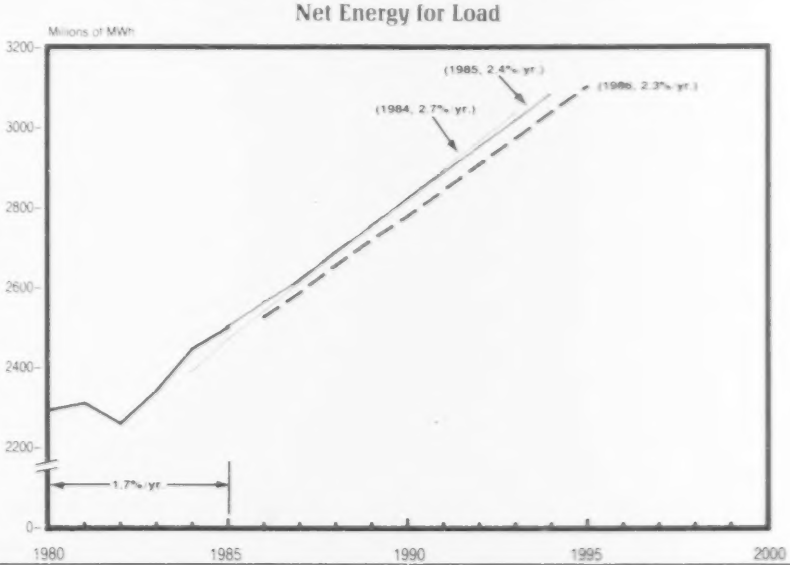


Table 3 — Recent Forecast Average Annual Growth Rates (%/Year)

		NERC U.S.	NERC Canada	NERC Mexico[b]
Summer Peak Demand	**This Year (1986-1995)**	**2.2**	**2.9 (3.0)[a]**	**7.1**
	Last Year (1985-1994)	2.2	3.0	
	Two Years Prior (1984-1993)	2.5	3.0	
Winter Peak Demand	**This Year (1986-1995)**	**2.3**	**2.8 (2.8)[a]**	**7.1**
	Last Year (1985-1994)	2.3	3.0	
	Two Years Prior (1984-1993)	2.5	3.2	
Annual Energy	**This Year (1986-1995)**	**2.3**	**3.1 (3.1)[a]**	**7.3**
	Last Year (1985-1994)	2.4	3.1	
	Two Years Prior (1984-1993)	2.7	3.1	

[a]Parenthesized figure includes Nova Scotia [b]Northern portion of Baja California, Mexico only

demand and energy forecasts each year, it now appears that the forecasts have stabilized.

Figures 2, 3, 4 and 5 further illustrate the base peak demand and energy forecasts made in 1984, 1985 and 1986 for the United States and Canada. The peak demand forecasts made in each of these years for the United States are practically identical. In Canada, the peak demand forecasts made in 1985 and 1986 are essentially the same and are slightly higher than the forecast made in 1984. Energy forecasts continue to be reduced in the United States, but are being increased in Canada.

Forecast Uncertainty

Changes in electric demand and energy consumption are reflections of the ways in which people use electricity in their domestic, commercial, and industrial activities. Utilities anticipate changes in electricity consumption by watching a wide range of indicators, some of which are economic performance, new technologies, population, government policies, life styles, conservation efforts and demographics. With these aspects of society changing, it is reasonable to expect the long-term forecasts to vary from year to year.

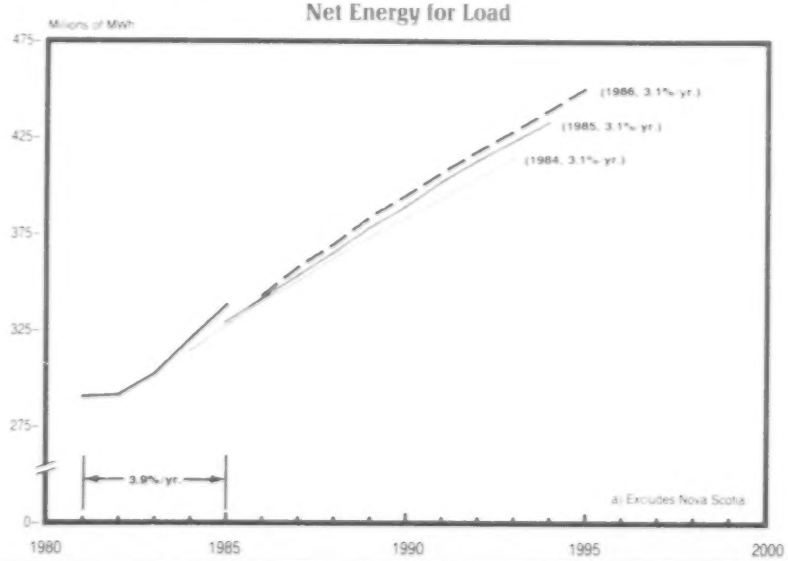
NERC's base forecasts for peak demand and energy are aggregates of the most probable forecasts of all the member utilities. It is intended that the likelihood of exceeding the base forecast is equal to the likelihood of the forecast not being reached. To avoid implying a degree of certainty not intended, reasonable bounds for potential variation from the forecast have been defined.

These bounds, or sensitivity bandwidths, for the 1986-1995 aggregated base forecasts of the United States and Canada are

Figure 5

NERC (Canada) Comparison of Recent Forecasts[a]

Net Energy for Load



shown by the shaded areas in Figures 6, 7, 8 and 9. The sensitivity bands are defined such that there is about a 10% chance of exceeding the upper bound and a 10% chance of demand being lower than the lower bound. Note that the upper bound growth rate of about 4% per year in these figures is much less than the high growth rates experienced in the years preceding 1973.

In developing the United States bandwidths, the energy-related indicators identified as best replicating the growth in electric peak demands were:

- Real gross national product
- Real price of electricity
- Industrial employment

Figure 6

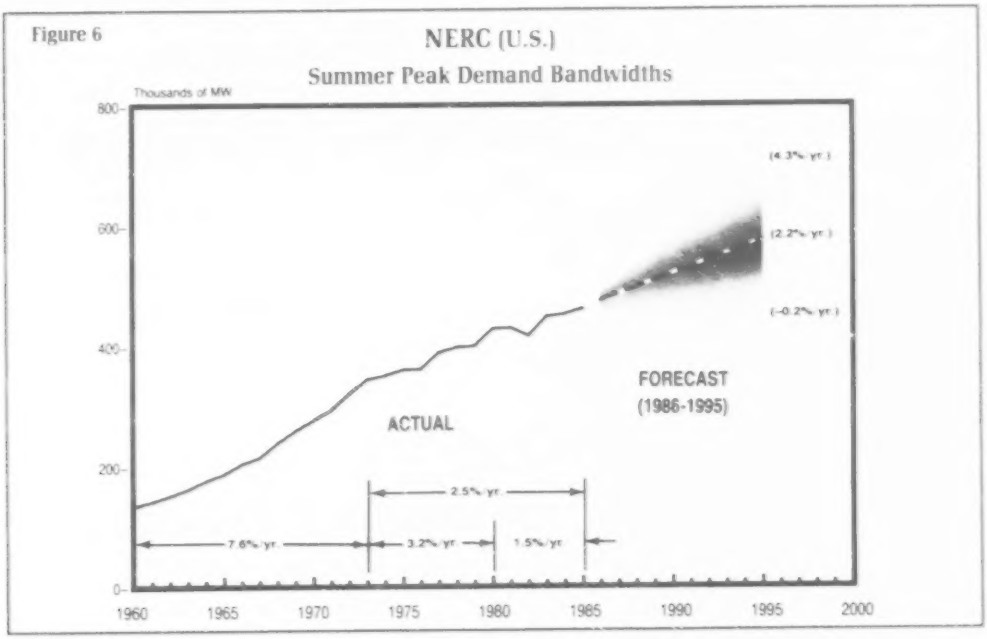
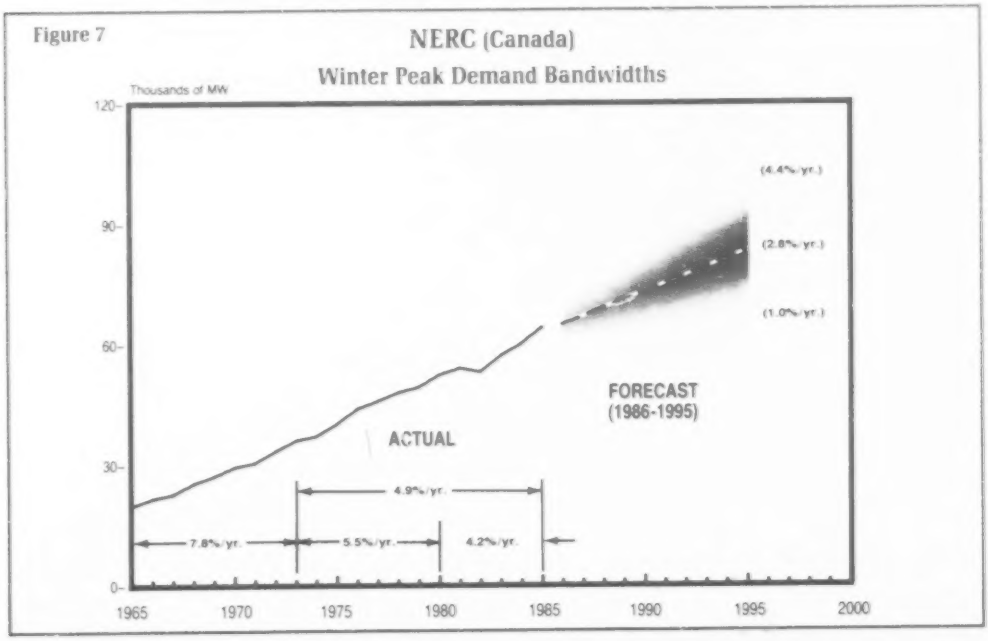


Figure 7



Established relationships between these indicators and peak demand were used with high and low estimates of the indicators to develop corresponding high and low band peak demand projections as shown in Figure 6. Energy bandwidths in Figure 8 were developed by applying forecast annual load factors to the demand projections.

Bandwidths for Canadian projections as shown in Figures 7 and 9 were derived by adding the respective high and low forecast scenarios as provided by each Canadian utility.

It would be incorrect and misleading to apply the ranges of the forecasts shown in these figures to the forecasts of any of the nine NERC regions or to those of individual utilities since the ranges shown represent a composite of all utilities.

Figure 8

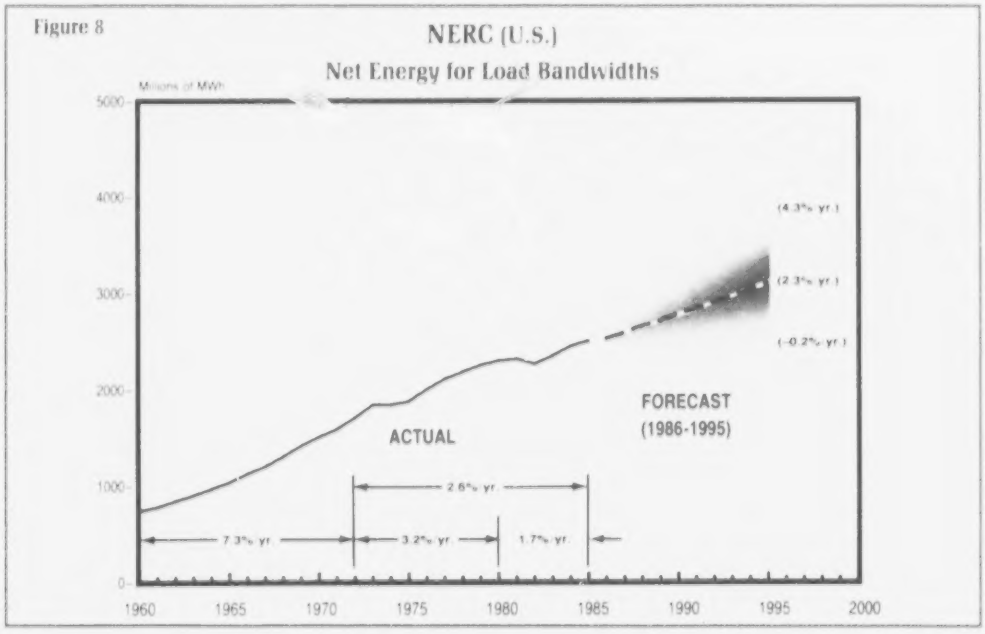
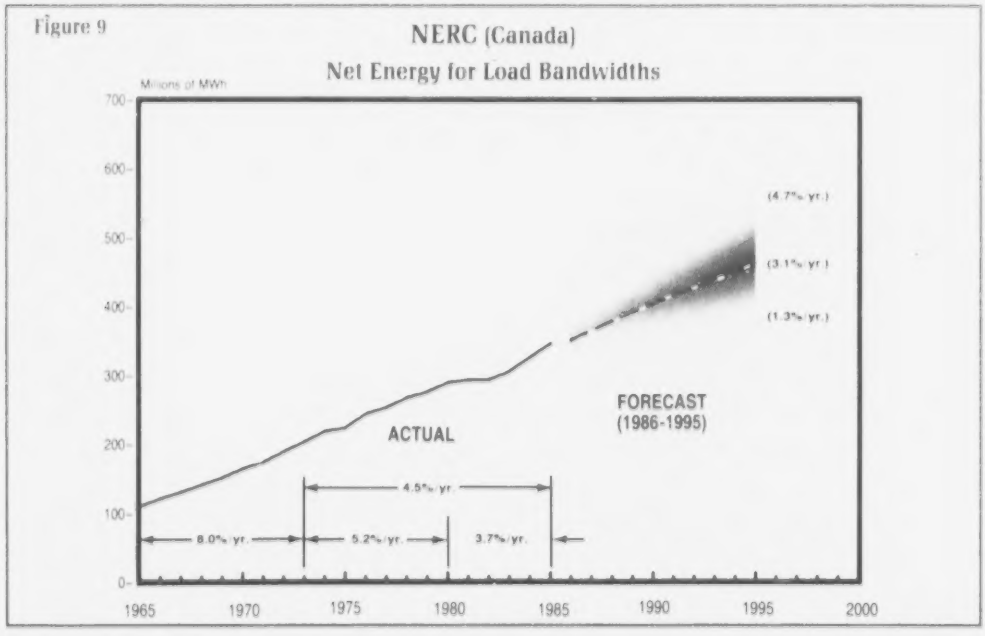


Figure 9



Loads and Resources

Generating Capacity

Planned capacity additions over the 1986-1995 period are 86,700 MW in the U.S. and 13,800 MW in Canada. These planned additions are less than last year's 10-year projections by about 26,000 MW in the U.S. and by 1,200 MW in Canada.

Of the total planned capacity additions, about 41% (35,000 MW) in the U.S. and 35% (4,900 MW) in Canada are not yet under construction. Over one-third of the capacity not yet under construction is comprised of coal-fired steam units of 100 MW or larger with in-service dates implying construction times of 5 to 9 years. It will be difficult for utilities to complete these units on time.

Utilities are clearly moving toward smaller, shorter lead time generation alternatives with an increased reliance on cogenerators, small power producers and other non-utility generators. This non-utility generation is projected to account for 11% of the U.S. planned capacity additions over the next 10 years, but only about 1% of those in Canada. By 1995, the sum of the cogeneration and small power production capacities will equal about 3% of NERC's total capacity resources.

Recent Experience

The total installed generating capacity, as shown in Table 4, increased in the U.S. and Canada by 2.9% and 1.8%, respectively, in 1985 over 1984. The electrical energy generated by this capacity from primary energy sources (pumped storage generation excluded) increased in 1985 to 2,438 million MWh in the U.S. and to 347 million MWh in Canada. The actual 1985 electrical energy production for the U.S. exceeded 1984's production by 2.4% but did not quite reach the 1985 forecast. In contrast, Canada's electrical energy production exceeded 1984's production by 7.6% and its 1985 forecast by 5.1%. The high production levels in Canada reflect both the high growth of native load and record levels of energy sales to the United States.

Figure 10

NERC (U.S.) Generating Unit Additions

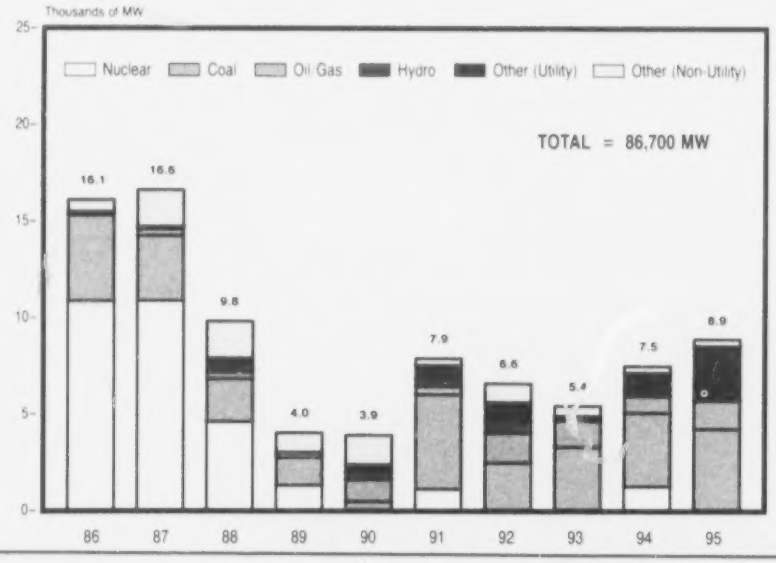


Table 4 — 1985 Installed Generating Capacity and Electric Energy Production Experience

	1984 Actual	1985 Actual	Actual Change %	1985 Forecast	Actual vs Forecast %
NERC — U.S.					
Generating Capacity — Summer (Thousands of MW)	604.2	**621.6**	2.9	616.8	0.8
Electric Energy Production[a] (Millions of MWh)	2380.9	**2438.4**	2.4	2448.9	-0.4
NERC — Canada[b]					
Generating Capacity — Winter (Thousands of MW)	77.5	**78.9**	1.8	80.4	-1.9
Electric Energy Production[a] (Millions of MWh)	322.6	**347.3**	7.6	330.5	5.1

[a]Total electric energy produced by primary energy sources (pumped storage generation excluded) [b]Excludes Nova Scotia

1986-1995 Forecast

Projections of generating unit additions, retirements, and oil-to-coal conversions during the 1986-1995 forecast period are summarized in Table 5 for the U.S., Canada and a small portion of Mexico. Planned capacity additions of 101,000 MW for NERC are about 27,000 MW less than last year's 10-year (1985-1994) forecast.

Projected generating unit retirements of 12,000 MW in the U.S. and about 200 MW in Canada are about the same as last year's 10-year projections. Oil-to-coal conversions are expected to be only 1,400 MW in the 10-year period, thus continuing a decreasing trend of the last few years. The increased attention being given to extending the life of existing units and to improving availability is influencing decisions on capacity additions, deferrals, cancellations and retirements.

Coal and nuclear generating units account for 70% of the U.S. planned additions. All other types of utility generation will comprise another 19%, while cogeneration and small power production facilities will provide the remaining 11%. In Canada, nuclear, hydro and coal generating units will comprise 95% of the capacity additions. On the other hand, the NERC portion of Mexico is projecting only oil and geothermal unit additions to its capacity mix.

The yearly planned capacity additions for the U.S. and Canada are detailed by fuel type in Figures 10 and 11, respectively. Over the next few years, the completion of nuclear units, already under construction, will dominate capacity additions in the U.S. and Canada. During the latter half of the forecast period, U.S. additions will shift to coal units. In Canada, the shift will be mainly to hydro capacity. The effect of the planned capacity

Figure 11

NERC (Canada) Generating Unit Additions

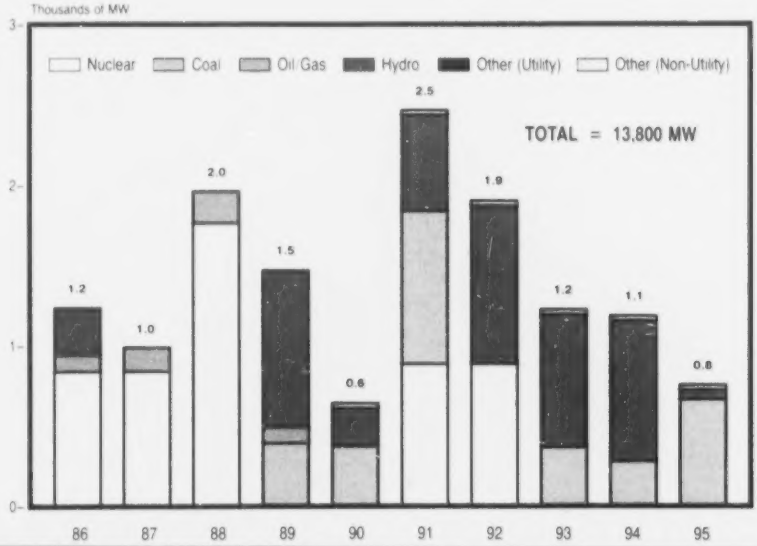


Table 5 — NERC Generating Unit Additions, Retirements and Conversions (1986-1995)

	NERC-U.S.		NERC-Canada		NERC-Mexico[c]		NERC-Total	
Type	Thousands of MW	% of Total	Thousands of MW	% of Total	Thousands of MW	% of Total	Thousands of MW	% of Total
Nuclear	29.8[a]	34.4	5.2	37.6	0.0	0.0	35.0[d]	34.7
Coal	30.7	35.4	3.0	21.8	0.0	0.0	33.7	33.3
Hydro	2.4	2.7	4.9	35.3	0.0	0.0	7.3	7.2
Oil/Gas	7.7	8.9	0.5	4.0	0.3	62.6	8.5	8.4
Pumped Storage	1.4	1.6	0.0	0.0	0.0	0.0	1.4	1.4
Other (Utility)	5.1[b]	5.9	0.0	0.0	0.2[c]	37.4	5.3	5.3
Other (Non-Utility)[d]	9.6	11.1	0.2	1.3	0.0	0.0	9.8	9.7
Additions	86.7	100	13.8	100	0.5	100	101.0	100
Retirements	11.8		0.2		0.0		12.0	
Conversions (Oil-to-Coal)	1.3		0.1		0.0		1.4	

[a]Perry 2, Seabrook 2, WNP1, and WNP3 nuclear units are not included
[b]Includes 973 MW of geothermal, 537 MW of miscellaneous, and 3,610 MW of unidentified capacity
[c]All geothermal capacity
[d]Cogeneration and small power production facilities under PURPA and other non-utility generation reported by electric utilities. Of the total, 5,533 MW (U.S.) and 180 MW (Canada) are projected to be cogeneration capacity.
[e]Northern portion of Baja California, Mexico only

additions over the 1986-1995 forecast period on total installed generating capacity is shown in Figure 12 for U.S., Canada and Mexico.

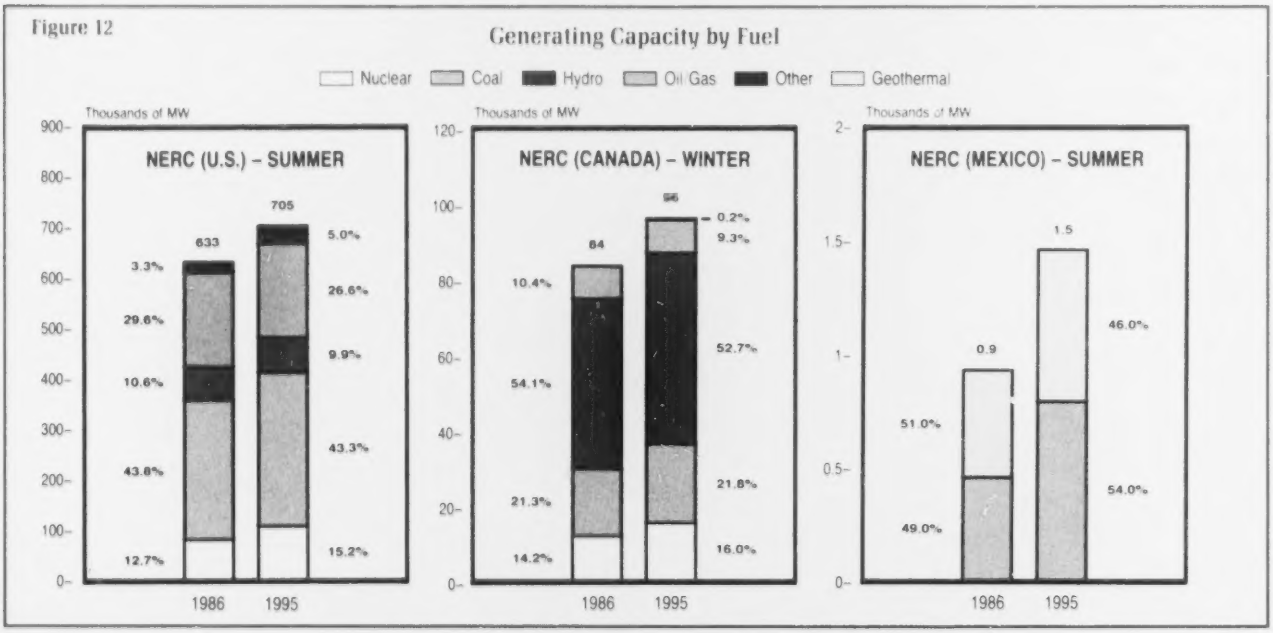
Figure 13 shows that, of the 633,000 MW of installed generating capacity in the U.S. in 1986, coal-fired capacity is projected to provide about 56% of the utility-generated electricity. Coal is expected to maintain its more than 50% share of annual electrical energy production in the U.S. through 1995. Hydro will be the mainstay of electrical energy production in Canada over the 1986-1995 period as shown in Figure 14. The domination by geothermal generation is depicted by Figure 15 for the northern region of Baja California, Mexico.

Electrical energy from nuclear capacity in both the U.S. and Canada is expected to increase over the next ten years. Electrical energy from oil is projected to increase slightly.

Cogeneration and Small Power Production Facilities

The U.S. utilities have reported to DOE under IE-411 that they expect capacity additions of about 9,787 MW from cogenera-

Figure 12



tion and small power producers in the 1986-1995 period. Table 6 shows that the majority of the identifiable non-utility generation will be fired by natural gas. Table 7 also indicates those NERC regions where such capacity additions are projected to be installed over the forecast period. Very little of this type of capacity is expected in Canada.

NERC surveyed the nine Regional Reliability Councils recently to obtain more consistent data for this type of capacity than now contained in IE-411 reports. Some of this generation is now considered a reduction in load and other non-utility generation is considered as imports into a region. Thus, the 9,787 MW of planned capacity additions (from IE-411) over the 1986-1995 forecast period reported in Tables 5, 6 and 7 do not include all planned additions, but only that portion of the cogeneration and small power production facilities and other non-utility generation additions which utilities have chosen to report as capacity additions.

Table 6
Non-Utility[a] Generation Additions By Fuel Type

Fuel Type	1986-1995 MW	% of Total
Natural Gas	3,032	31.0
Hydro	507	5.2
Coal	461	4.7
Geothermal	368	3.7
Wind	177	1.8
Solar	76	0.8
Refuse (Solid Waste)	40	0.4
Wood Wood Wastes	20	0.2
Unknown	5,106	52.2
Total	9,787	100

[a]Cogeneration and small power production facilities under PURPA and other non-utility generation reported by electric utilities. Data is from Regional Reliability reports to DOE under IE-411.

Table 7 — Non-Utility[a] Generation Included In NERC Generating Unit Additions (1986-1995)

Regions	Non-Utility Additions — MW	% of 1986-1995 Regional Additions
ECAR	212	2.4
ERCOT[b]		
MAAC	567	13.3
MAIN	160	3.6
MAPP		
NPCC	1,773	11.0
SERC		
SPP	300	4.6
WSCC	6,775	31.1
Total	9,787	9.7

[a]Cogeneration and small power production facilities under PURPA and other non-utility generation reported by electric utilities. Data is from Regional Reliability reports to DOE under IE-411.

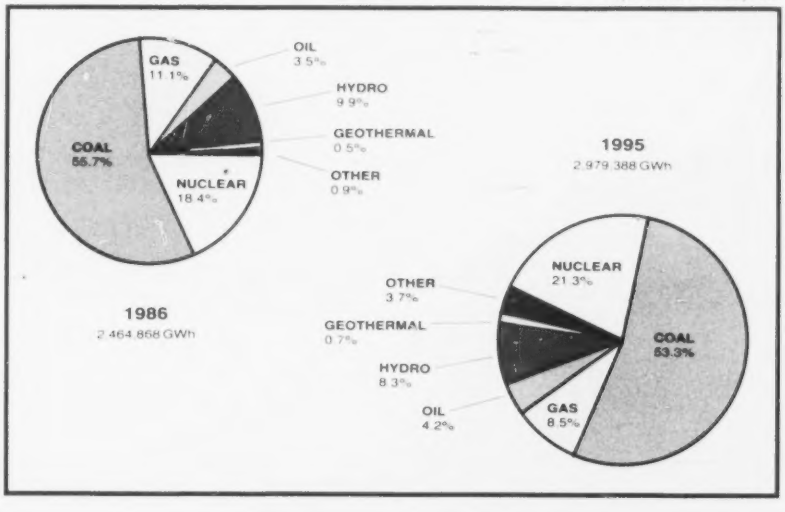
[b]ERCOT has included about 3,000 MW of capacity purchases from non-utility generation as imports rather than as generation additions.

The NERC survey showed that all regions of NERC report some level of activity in cogeneration and small power production by 1995. Some regions expect to see significant amounts of this type of capacity in service within the next 10 years. By the summer of 1995, ERCOT projects that non-utility generation will represent over 7% of its total planned capacity. Survey results, tabulated in Table 8, show that the total

Figure 13

NERC (U.S.) Electric Energy Production By Fuel

Projections as of January 1986



Cogeneration and Small Power Production

The Public Utility Regulatory Policies Act (PURPA) of 1978 defines certain cogeneration and small power production facilities as Qualifying Facilities (QF's) from which utilities are required to purchase electric energy at rates which do not exceed the utilities' avoided costs.

Under PURPA, cogeneration refers to the production of both electric energy and other useful forms of energy (steam, heat, etc.) from the same fuel source. There is no limit on cogenerator unit size. A small power production facility is limited to 80 MW at a given site and is required to produce electric energy primarily from biomass, waste, renewable resources or any combination thereof. The use of coal, oil or natural gas in its electric production is limited to 25% or less. Utility ownership of facilities under PURPA is limited to 50% or less.

For many years prior to PURPA, some customer-owned generators have operated as cogenerators and have supplied electric energy to electric utility systems. Since 1978, PURPA, favorable tax incentives and other factors have contributed to a resurgence in such non-utility generation.

In this report, "cogeneration and small power production facilities" or "non-utility generation" are synonymous. The terms include non-utility generation not covered by PURPA as well as qualifying cogeneration and small power production facilities under PURPA which currently operate or are planned to operate as electric generators connected to electric utility systems.

capability of cogeneration and small power production facilities projected to be in service by 1995 is about 25,000 MW or about 3% of NERC's total planned capacity resources in the summer of that year. Approximately 8,000 MW of the 25,000 MW will be in service by the end of 1986.

Table 8
1986 NERC Survey of Cogeneration and Small Power Production Facilities By Summer 1995

Regions	Total Projections MW	% of Total Capacity Resources
ECAR	954	0.9
ERCOT	4,845	7.6
MAAC	2,554	5.0
MAIN	465	0.9
MAPP	191	0.5
NPCC	3,511	2.7
SERC	1,973	1.3
SPP	1,466	2.1
WSCC	9,276	5.9
NERC Total	25,235	3.1

Generating Unit Construction

Table 9 indicates the construction status of the planned generating unit additions over the 1986-1995 period. All planned nuclear units for this period are in some stage of

Figure 14

NERC (Canada) Electric Energy Production By Fuel

Projections as of January 1986

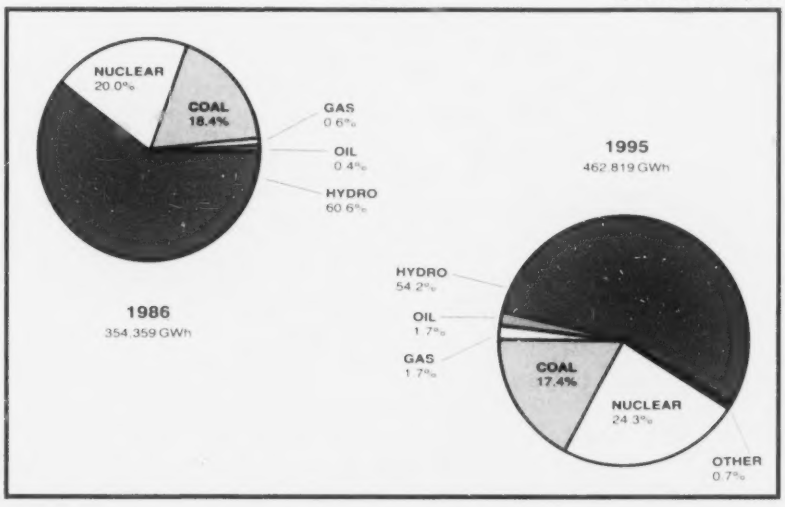


Table 9 — Construction Status of NERC Generating Unit Additions (1986-1995)

	NERC-U.S.			NERC-Canada		
	Number of Units	Thousands of MW	% of Total MW	Number of Units	Thousands of MW	% of Total MW
Nuclear[a]						
Not yet under construction[c]	0	0.0	0.0	0	0.0	0.0
Under construction (<50%)	2	2.2	7.4	2	1.8	33.9
Under construction (>50%)	25	27.6	92.6	4	3.4	66.1
Total Nuclear	27	29.8	100	6	5.2	100
Coal						
Not yet under construction[c]	26	11.7	38.3	6	1.9	62.1
Under construction (<50%)	17	10.8	35.1	3	1.1	37.9
Under construction (>50%)	14	8.2	26.6	0	0.0	0.0
Total Coal	57	30.7	100	9	3.0	100
Hydro[b]						
Not yet under construction[c]	127	1.9	79.7	13	2.4	49.3
Under construction (<50%)	11	0.4	18.5	14	2.2	44.7
Under construction (>50%)	4	0.1	1.8	1	0.3	6.0
Total Hydro	142	2.4	100	28	4.9	100
Other (Utility)						
Not yet under construction[c]	117	12.4	87.6	3	0.4	81.2
Under construction (<50%)	17	1.6	11.3	0	0.0	0.0
Under construction (>50%)	8	0.2	1.1	1	0.1	18.8
Total Other	142	14.2	100	4	0.5	100
Other (Non-Utility)[d]						
Not yet under construction	—	9.4	97.6	—	0.2	100
Under construction (<50%)	—	0.2	2.1	—	0.0	0.0
Under construction (>50%)	—	<0.1	0.3	—	0.0	0.0
Total Non-Utility	[e]	9.6	100	[e]	0.2	100
Total (All Units)						
Not yet under construction	—	35.4	40.9	—	4.9	35.5
Under construction (<50%)	—	15.2	17.5	—	5.1	36.8
Under construction (>50%)	—	36.1	41.6	—	3.8	27.7
Total (All Units)	[e]	86.7	100	[e]	13.8	100

[a] Seabrook 2, Perry 2, WNP1, and WNP3 are in some stage of construction but are not included in these totals.
[b] Does not include pumped storage.
[c] Includes utility units planned but not utility authorized, units with regulatory approval pending, and units with regulatory approval received but not yet under construction.
[d] Cogeneration and small power production facilities under PURPA and other non-utility generation reported by electric utilities.
[e] Non-utility generation additions are not available by unit.

construction.[1] Only 62% and 38% of the planned coal units in the U.S. and Canada, respectively, are in some phase of construction. Only 20% of U.S. and 50% of the Canadian planned hydro additions are under construction. Similar figures are shown for other utility and non-utility planned capacity additions.

Overall, about 41% of the U.S. generating capacity additions and about 35% of the Canadian generating capacity additions which are needed to meet the requirements of the electric utilities' customers by 1995 are not yet under construction. Financial, regulatory and other institutional factors discussed elsewhere in this report are discouraging utilities from moving ahead with plans for large, baseload generation projects. The last major coal unit ordered was Fayette #4 (400 MW) by the Lower Colorado River Authority in January 1985 and now scheduled to be in service in July 1992. The last 2 nuclear units ordered were Carroll County #1 and #2 by Commonwealth Edison in 1978.[1] Table 10 shows that 31,000 MW of the planned

[1] Seabrook 2 (1,150 MW), Perry 2 (1,179 MW), WNP1 (1,250 MW) and WNP3 (1,240 MW) are not included in any tables or figures in this section. These units are in some stage of construction but are under review and are not counted as part of the NERC capacity during this review period. The Carroll County units are scheduled to be in service beyond 1995.

Table 10 —Additions (100 MW or More) Not Yet Under Construction — Thousands of MW (1986-1995)

Units	NERC U.S.	NERC Canada	NERC Mexico	NERC Total
Coal	11.5	1.9		13.4
Hydro	1.1	1.9		3.0
Gas	2.6	0.4		3.0
Oil	1.4		0.1	1.5
Pumped Storage	0.1			0.1
Other (Utility)	3.9			3.9
Other (Non-Utility)[a]	6.2			6.2
Total	26.8	4.2	0.1	31.1

[a]Cogeneration and small power production facilities under PURPA and other non-utility generation reported by electric utilities.

101,000 MW capacity additions in the forecast period involve units of 100 MW or larger, with projected in-service dates allowing only 5 to 9 years for construction (Figure 16 for U.S. and Figure 17 for Canada). Since it typically requires 8 to 10 years to license and build large coal units, it seems likely that much of this capacity will be completed late or replaced with shorter lead time options.

The U.S. capacity reductions are primarily in coal, nuclear, and other miscellaneous utility capacity. The increase in projected capacity purchases from cogeneration and small power production facilities is not enough to offset the reductions. In Canada, the capacity increases are mainly in hydro and coal unit additions.

Comparisons of Recent Projections

Since last year's review, substantial changes have been made in utility resource plans. The changes include additions and cancellations, rescheduling of unit service dates and generation retirement deferrals. Table 11 compares the common period (April 1986-December 1994) of the current and last year's projections. Over this common period, the U.S. planned additions decrease by about 10,000 MW while in Canada, planned capacity additions increase about 1,000 MW.

Figure 15

NERC (Mexico) Electric Energy Production By Fuel

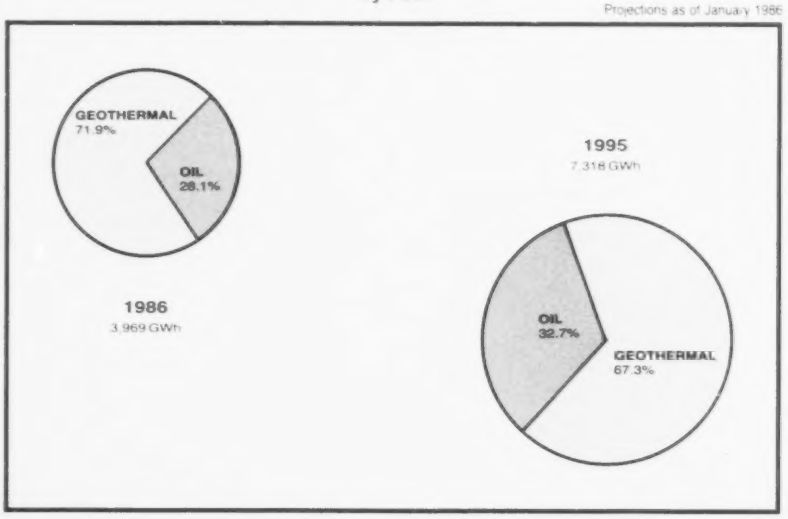


Table 11 — Changes in Planned Generating Capacity Additions for the 1986-1994 (Common) Period — Thousands of MW

	NERC-U.S. Forecast			NERC-Canada Forecast		
Unit Type	**Current**	**Last Year's**	**Change**	**Current**	**Last Year's**	**Change**
Coal	26.5	36.7	-10.2	2.3	2.0	0.3
Nuclear	29.8	30.8	-1.0	5.2	5.1	0.1
Hydro	2.3	2.6	-0.3	4.8	4.2	0.6
Oil/Gas	6.2	6.3	-0.1	0.6	0.5	0.1
Other (Utility)	3.7	5.4	-1.7	0.0	0.0	0.0
Other (Non-Utility)	9.3	5.8	3.5	0.2	0.1	0.1
Total	77.8	87.6	-9.8	13.1	11.9	1.2

Figure 16

NERC (U.S.) Planned Generator Additions Not Yet Under Construction

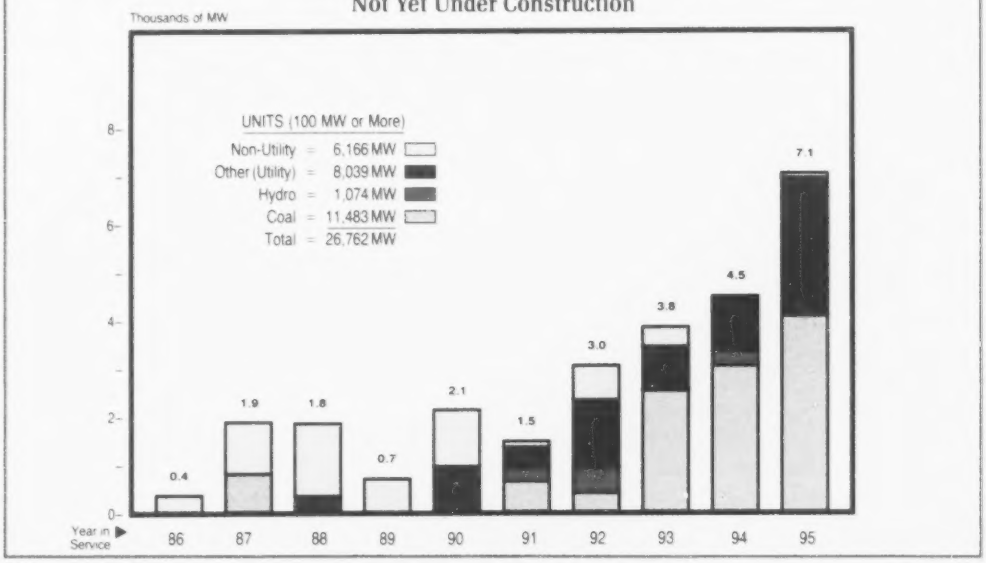
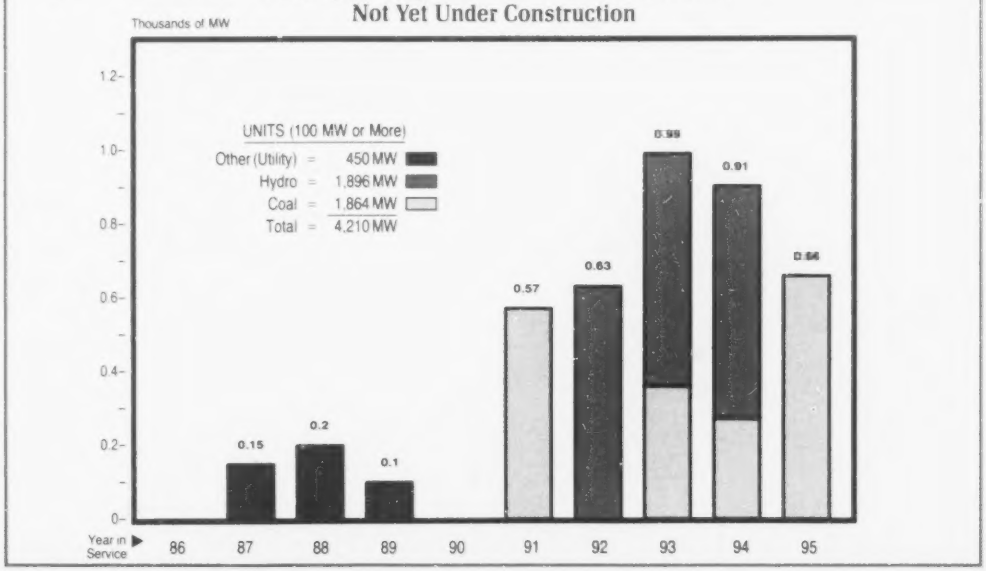


Figure 17

NERC (Canada) Planned Generator Additions Not Yet Under Construction



Assessment of Power Supply Adequacy

Regional generating capacity margins are projected to be adequate over the decade but some will decline, approaching minimum acceptable levels by 1995.

Priorities for assuring adequacy of electric supply during the 1990's include keeping existing generating units in operation, maintaining schedules for units under construction, shortening lead times for the siting, licensing and construction of new units and assuring the timely implementation of load management and conservation programs. Reasonable regulatory treatment of new capacity for rate purposes will be essential if adequate new capacity is to be committed by utilities.

Adequacy in some regions will also be dependent upon the timely completion and continued operation of non-utility generation.

Capacity Margin

To provide a reliable electric supply, all systems require generation resources to be somewhat greater than the expected peak demand. Margin is the amount by which the planned resources exceed the peak demand. Capacity margin is equal to margin divided by the total planned resources and is expressed as a percentage. A suitable capacity margin is needed to provide reliability of supply by allowing for planned or forced outages of generating equipment, for equipment deratings due to various causes, and for differences between actual demands and those forecast.

The suitable capacity margin may not be the same for each utility, but varies to reflect different circumstances such as the duration of the peak load season and the outage rates for different sizes and types of generation (hydro, coal, oil, gas or nuclear).

Planned Load and Capacity

The planned capacity margins in 1986 and 1995 for each region are shown in Table 12. The capacity margins expected in each year for the United States and Canada are shown in Figure 18.

Figure 18 (U.S. and Canada) Estimated Capacity Margins

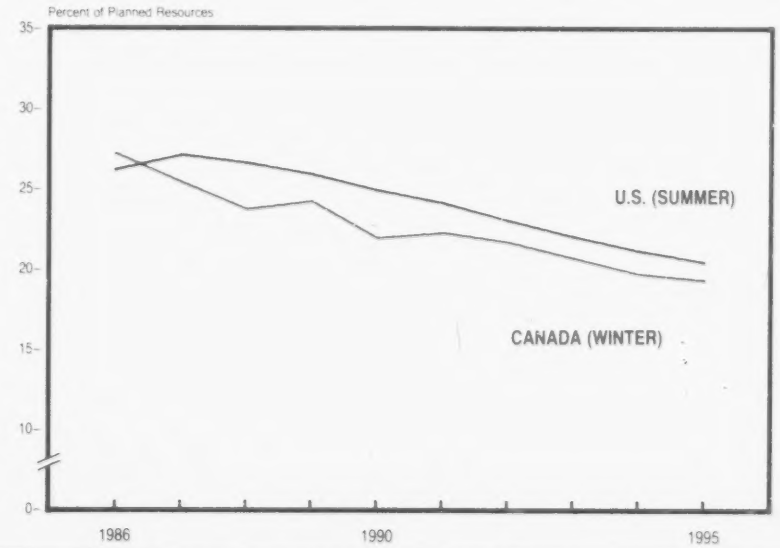


Table 12 — Estimated Regional Capacity Margins (% of Planned Resources)

Regions (U.S.)	1986 Summer	1995 Summer
ECAR	26	20
ERCOT	17	18
MAAC	25	20
MAIN	23	20
MAPP	27	20
NPCC	25	21
SERC	25	19
SPP	29	17
WSCC	31	25
NERC (U.S.)	26	20
Regions (Canada)	**Winter**	**Winter**
MAPP	18	23
NPCC	28	19
WSCC	29	18
NERC (Canada)	27	19

While adequate capacity resources are planned through 1995 to meet projected demands, the planned capacity margin in some regions will be near the minimum required for reliable supply.

The lower capacity margins planned by 1995 will result in less flexibility for utilities to meet situations that are different from those expected. One result will be reduced opportunities for individual utilities to purchase firm capacity from neighboring systems and thus increased likelihood of load curtailments should a temporary capacity shortage develop in an area. Any of the following developments could lead to capacity shortages:

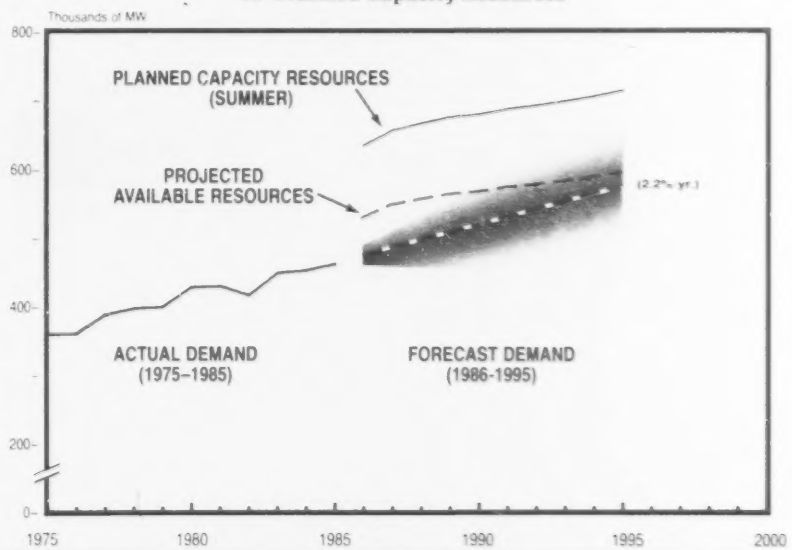
- Planned capacity additions are not completed on schedule
- Acid rain legislation forces unit shutdowns or deratings
- Additional nuclear safety concerns result in unit deratings or delays in operation
- Large blocks of cogeneration either not being completed or being forced out of operation by economic factors or government policy
- Load growth is higher than forecast

Historical peak demands and projected future demands are shown in Figures 19 and 20 for the United States and Canada respectively. The base projections indicated by the heavy dashed line are considered to be the most likely for expected future conditions. The considerable range of uncertainty regarding future loads is indicated by the shaded area of the diagrams. The shaded area is the same as shown in the chapter titled "Loads and Resources — Peak Demand and Energy." It is the intent of the forecasters that a 50% likelihood exists that the future peak demand will exceed the base projection to some degree. The planned capacity resources as shown in the uppermost dotted line are expected to be adequate to supply the projected base demands through 1995.

The effect of possible higher load growth is also illustrated in Figures 19 and 20. The line labeled "Projected Available Resources" provides an indication of the average capacity that can be expected to be available to supply the peak demand. This line illustrates that not all installed capacity will be available, and is based on historical capacity availability from the NERC Generating Availability Data System (GADS) report and from other sources. For the United States, the line

Figure 19

NERC (U.S.) Load Forecasting Sensitivity vs Planned Capacity Resources



reflects that an average of about 17% of the planned capacity resources is not expected to be available to supply the peak demand. For Canada, the corresponding amount is about 10%, reflecting different circumstances such as a greater proportion of hydro generating capacity which inherently has a higher average availability. Load growth at a rate corresponding to the higher range of the shaded area of Figures 19 and 20 could result in inadequate reliability as early as about 1990 in both the United States and Canada if no corrective action were taken by utilities. Thus, planned capacity resources are adequate to supply the base projected peak demands through 1995, but there will be little additional capacity to meet unexpected conditions.

If a trend toward higher growth should begin, prompt recognition of the trend will be essential to initiate an adequate response. Since one or two years of higher-than-forecast demands may be caused by temporary conditions, at least three years are required to identify a new trend in growth rate. Once an increase in growth rate is identified, the utilities may need short lead time options to provide capacity. Recognizing that the strategy must also require minimum risk of capital in an uncertain future, most utilities will be combining these needs into a general strategy for resource planning.

After completion of new generating capacity now under construction, most utilities are implementing a low capital commitment strategy for future resource planning usually involving the following features:

- Maximize availability and utilization of existing resources
- Purchase power if available from other utilities, cogenerators and small power producers
- Expand load management and conservation programs
- Install short lead time generating capacity

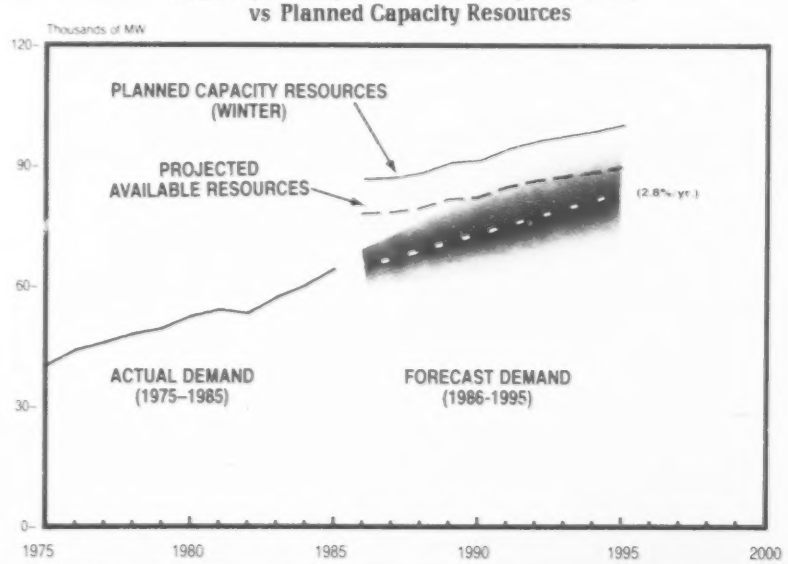
Capacity Construction Plans

In Canada, 5,200 MW of nuclear capacity, 1,100 MW of coal-fired capacity, and 2,500 MW of hydro capacity presently planned for service over the next 10 years are already under construction. Another 4,900 MW or 35% of the total planned capacity additions for Canada are not yet under construction. However, the expectation is very high that all or most of this capacity will come into service on schedule.

The United States' situation for units under construction is less favorable than Canada's situation. Of the 15 nuclear units scheduled for commercial operation during 1985, only 7 (totaling 7,903 MW) were placed in service. At present, there are 27 units totaling 29,800 MW of nuclear capacity under construction in the United States and planned for service over the next 10 years. Fifteen of these 27 units have had their service dates delayed an average of 10 months since last year's review. Only one nuclear unit had its service date advanced by 3 months. In view of continuing difficulties in satisfying all regulatory requirements to obtain operating licenses, the service dates of these nuclear units must be considered questionable. Seabrook 2, Perry 2, WNP1 and WNP3, all of which are in some stage of construction, are not included in the above figures or discussion. These 4 units are under review and are not counted as part of the NERC capacity during this 10-year review period. Other nuclear units, including Carroll County 1 & 2, are scheduled for initial service beyond 1995.

Figure 20

NERC (Canada) Load Forecasting Sensitivity vs Planned Capacity Resources



The serious accident at the Chernobyl nuclear station near Kiev (USSR) has resulted in much controversy and speculation in the public and scientific press. Information about the accident — its cause and effects — is presently sparse and seemingly incomplete. It is premature to make any judgment as to the effect on the North American nuclear programs, and on consequential changes in bulk electric system reliability.

United States' coal units are not immune to problems, but the outlook for them is much brighter than for nuclear. Some 13 coal units totaling 5,200 MW went into service in 1985. At present, there are 31 coal units totaling 19,000 MW under construction in the United States and planned for service over the next 10 years. Only 3 of these 31 units have had some delay in their service date since last year's review, while 2 units have had their service dates advanced, indicating that the coal unit construction program already underway is essentially on schedule. However, 26 coal units totaling 11,700 MW are not under construction and 19 of these have been delayed an average of 22 months since last year's review. It is questionable if all of this capacity can be licensed and constructed by the time it is needed. Further, no construction was started on any large coal unit in the past year.

Oil Price Trends

The sharp decline in gas and oil prices experienced in early 1986 has enhanced the attractiveness of peaking and combined-cycle generation using these fuels. The developing technology in Integrated Gasifier Combined Cycle generation offers the potential of converting combined-cycle plants to coal at a later date. There is no evidence of a significant shift toward oil- and gas-fired generation within the 10-year forecast period.

Cogeneration and Small Power Production

The potential for cogeneration and small power production facilities has grown rapidly in the economic and political environment of the past several years. That growth could be affected by the recent decline in oil and gas prices. A January 1, 1986 Federal Energy Regulatory Commission Report indicates license applications under the Public Utility Regulatory Policies Act are currently at the 35,000 MW level and increasing. Continued growth toward the projected 1995 levels is dependent upon continuation of a favorable environment.

Development of non-utility generation potentially has both positive and negative effects on power supply adequacy.

Potentially Positive:

- Shorter lead time for these units is a potential benefit to utilities needing capacity
- Financing by others will ease utility capital requirements
- More efficient use of energy sources through cogeneration

Potentially Negative:

- Cogenerator will operate more in response to industrial process needs than to utility system customers' needs
- The operation of non-utility generation on a long-term basis is subject to its being profitable
- Cogeneration capacity is particularly susceptible to fuel availability and price changes
- Most cogenerators and small power producers will not respond to daily cycles in electric loads. During light load periods, utilities may be required to follow the load variations with low cost nuclear or coal units or spill water at hydro units in order to accept output from cogenerators or small power producers.
- Transmission access policies may result in loss of utility transmission capacity and an uncertain situation in the planning of transmission additions
- An increased load-following function will fall to the utility's generation which will result in raising costs, maintenance and possibly outage rates

The PURPA legislation is not specific with regard to the conditions and obligations a Qualifying Facility (QF) must meet with respect to the planning and operation of the electric power system and the allowed effects on the system's reliability. In this vacuum, the individual states have been adopting standards that differ widely.

Utilities need flexibility to negotiate with QF's on issues such as energy and capacity costs, wheeling costs, connection requirements, and generation schedules. A utility should not be required to accept energy it cannot economically or reliably use and it should never be required to pay more than avoided cost. For reliability, utilities need commitments from producers which provide insurance against the QF ceasing operation unilaterally. These considerations have both economic and reliability implications. It is too early in the development of this type of capacity to appraise its impact fully. It is a development which will bear watching as the utility systems gain experience in the years ahead.

Load Management and Conservation

Utilities are counting on load management and conservation programs to restrain load growth in the future. The extent of this dependence is not immediately apparent, however, since the effect of these programs is included in the load forecasts. For example, the New York Power Pool is forecasting an increase in summer peak demand of about 5,800 MW over the next 16 years — a compound annual growth rate of 1.4%. It is projected that, without the effect of conservation and load management programs, growth in peak demand would be about 1,900 MW higher, or 7,700 MW — a compound annual growth rate of 1.8%.

If the load reduction goals of utility conservation and load management programs are not met, load could grow at a greater rate than forecast, requiring additional capacity commitments to maintain reliability. Customer acceptance of such programs has yet to be fully tested. Few of the utilities which have installed such systems have so far had to utilize them extensively. When capacity margins decline to the point where these systems will have to be used extensively and frequently, customers may decide that the resultant inconveniences outweigh the cost savings involved and opt to move out of such programs, resulting in higher than anticipated load levels and reduced reliability.

Acid Rain

The Canada-United States Joint Report of the Special Envoys on Acid Rain was released in January 1986. The report acknowledged that acid rain is a serious problem and that trans-boundary air pollution requires attention. The findings of this report were endorsed by President Reagan and Prime Minister Mulroney.

In the United States, legislation to establish a nation-wide acid rain controls program is undergoing consideration. One of the bills under development would cut sulphur dioxide emissions from coal-burning power plants and factories by about 40% over 10 years.

In Canada, the current national strategy is to reduce the sulphur dioxide emissions from fossil-fueled sources by 1990 to one-half of the 1980 emission levels.

Regulations to reduce SO_2 and NO_x emissions could have a severe adverse effect on reliability, especially if adequate implementation time is not provided. Any control equipment added to existing plants would require extensive unit downtime while installation is made. While the outages required for retrofitting new control equipment can be scheduled in phases, some new replacement capacity would still be required. Lead time and costs must be given appropriate consideration as new regulations are being developed.

Aging Capacity

One of the Council's concerns for future reliability in the United States is the aging of electric utility generating units. If all planned capacity additions are made on schedule, the average age of generating units in the United States will increase to 26 years by 1995. Currently, the average age is 17 years compared to 11 years in 1975.

The increasing average unit age is largely the result of the slowdown in generating capacity additions coupled with the renewed emphasis on unit life extension programs. Prior to 1974, when electric demands grew at roughly 7% per year, large amounts of capacity were added which caused the average age of generating units to decline. However, with lower projected growth rates and correspondingly fewer capacity additions, the average age of electric utility generators in the United States is increasing.

Many utilities have implemented extensive maintenance and life extension programs to improve availability and to maintain the reliability of their older generators. The results of these programs appear to be promising but have yet to be demonstrated over the long-term.

Transmission Issues

Utilities are finding it increasingly difficult to expand the transmission system to meet the future needs. The "impediments" to construction of new bulk power transmission include uncertainty about future benefits, lengthy licensing processes, conflicting jurisdictions and lack of incentives. Unless these impediments can be overcome, the strength and flexibility which have characterized the North American bulk electric transmission system will be diminished.

Because of the interaction of the interconnected systems, disturbances in one region can affect reliability of systems geographically remote from the disturbance, requiring continuous coordination among systems and regions. This problem has been further compounded by high levels of economy transfers during the last few years. Additions to the network are being proposed to enhance transfer capability and to assure reliability during transfers. These additions are often delayed by various impediments and factors which discourage utility investment. In some instances, reliability could be impaired if significant amounts of non-utility generation are installed at locations in the system where generation was not contemplated.

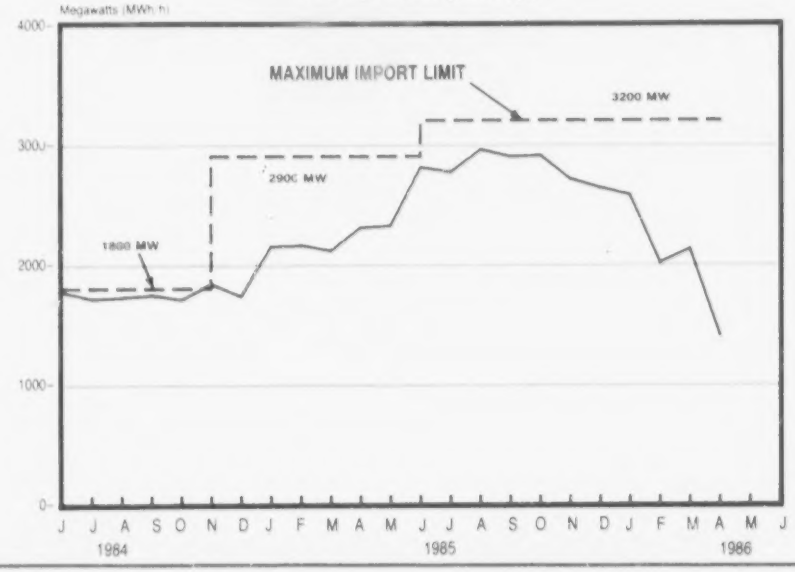
The Role of Transmission

Transmission facilities are a vital part of the North American electric power system. They perform several functions:

- Provide for movement of power from generating plants to the load centers of the utilities.
- Allow reduced installed generation capacity requirements for individual systems by sharing reserve capacity through interconnections.
- Enhance reliability and system security by providing multiple paths between generation sources and load centers.
- Provide for energy transfers from one geographic area to another to achieve overall system operating economies or to offset supply shortages.
- Interconnect the bulk power facilities to better withstand major disturbances without interruption of service to customers.

Figure 21

Florida Imports
Average Hourly Energy



Interconnections

In the one hundred-year history of electric power supply, utilities have grown from isolated systems supplying their customers from local resources to highly interconnected systems (or "interconnections") of generating stations and high voltage transmission lines encompassing large geographic areas and many individual utilities. Today, in the contiguous United States and Canada, there are four major interconnected areas: the Eastern Interconnection, the Western Systems Coordinating Council, the Electric Reliability Council of Texas, and Hydro-Quebec. The boundaries of these areas are shown in the accompanying map.

Interconnections of Utility Systems

Within each interconnected area, individual systems are connected together by transmission lines and electrically function as a single entity. The alternating current frequency will be the same at all points in an interconnected area. A simple manifestation of this phenomenon is that electric clocks will run at the same speed in all parts of an interconnected area. Another feature is that a disturbance occurring at any location in the interconnected area will be felt at all other points. Similarly, electricity transfers from one portion of an interconnected area to another will, to some extent, flow over transmission lines not in the direct path of the transfer.

When it is impractical or impossible to use alternating current (ac) transmission lines to connect two systems, high voltage direct current (dc) ties can be installed to allow electricity to be transferred between the systems.

The regional bulk power transmission systems are planned and operated to perform the above functions in conformance with established regional reliability criteria. In addition, policies, criteria and guides have been adopted within NERC to provide a framework for coordinated planning, engineering and operation by member utilities to promote reliability of the bulk power systems of North America.

Adequacy of Transmission System

The North American transmission system is judged to be adequate as planned through the next ten years to perform the above functions reliably and economically. The plans include new transmission facilities in all regions. Continued adequacy will depend upon timely completion of these facilities.

Economy Energy

Utilities have sought to minimize energy costs by transferring large amounts of coal and hydro-generated electricity to displace energy generated with higher cost oil and gas. In some areas, the transmission lines have been loaded to their limits for extended periods, resulting in reduced reliability. Heavy loadings continued in 1985.

The volatility of the oil market in the first part of 1986 has substantially changed the differential between coal- and oil-fired energy costs. This has led to at least a temporary reduction in energy transfers in several regions. The effect is illustrated for peninsular Florida imports in Figure 21. How long this trend will continue is uncertain and is dependent on how the price of various fuels change relative to each other.

It is expected that other significant transfers will continue through the mid-90's. Northeastern utilities are planning to increase imports from Canada. Hydro-generated energy in the Pacific Northwest will continue to be transferred to the Pacific Southwest. Significant transfers of coal-fired energy from west to east across the Mid-Atlantic region will continue and Florida systems are also expected to continue energy imports.

In 1985, purchases and sales of electric energy between utilities over interconnected transmission lines represented 20% of the

energy delivered to customers. Significantly increasing or even maintaining these energy exchanges in the future will be precluded unless the impediments to building transmission can be overcome.

Impediments to New Transmission

Some proposed key transmission additions required in the near term in various parts of the country are being denied or delayed.

Among general impediments to the construction of new bulk power transmission lines are:

- **The Requirement to Assure Future Benefits —** Justification of new transmission lines is accomplished through consideration of economic benefits and reliability requirements. Because of a history of good transmission system reliability, regulators are skeptical about reliability being a justification for new facilities, and on stating future economic benefits without having firm contracts. Consequently, transmission lines that might have been built in the past on a reasonable expectation of future benefits are not likely to go forward today.
- **Lengthy Licensing Procedures —** The lengthy regulatory process for issuing licenses for new transmission hampers new construction. Likewise, open-end regulatory processes, wherein an action can be reopened even after a license has been issued, present serious impediments to the timely construction of new facilities.
- **Conflicting Jurisdictions —** The potential still exists for conflicts between Federal and state, two or more states, or different agencies in the same state because of differing purposes and priorities. Such conflicts often lead to delays and impediments in the licensing of transmission while disagreements are resolved.
- **Lack of Incentives —** Regulatory treatment which assigns the economic benefits of a new facility solely to the customer, while the utility bears all of the risks, removes incentives for planning new transmission.

Examples of Specific Projects That Have Been Delayed:

- The Baltimore-Washington 500 kV loop has been delayed for more than 10 years by the certification process. In October 1985, after many years of litigation, certification for the final segments of this loop was completed. The process of acquiring necessary zoning and building permits for construction of these segments has begun. Completion of the loop is now scheduled for the early 1990's. The development of this EHV transmission network in the Washington, D.C. area will improve reliability of supply to the nation's capital. It will also add to the stability margin of the system and significantly increase the ability to transfer energy among MAAC, ECAR and SERC.
- Regulatory delays continue on the 500 kV transmission reinforcement in southwestern Ontario. These additions are required to transmit the full output of the Bruce generating plants on Lake Huron, provide a reliable supply for load in the southwestern portion of the province, and maintain transfer capability between Ontario and Michigan.
- The 500 MW South Texas dc tie (a second tie between ERCOT and SPP) has encountered lengthening delay because of routing consideration and alleged health effects of electrostatic and electromagnetic fields from the 155 mile HVDC line. An alternate project is being considered.
- A double circuit 345 kV interconnection involving Houston Lighting & Power Company, Texas Utilities Electric Company, and Texas Municipal Power Agency has been taken out of service by court order. In November 1985, a county court ruled that Houston Lighting & Power Company had abused its discretion in acquiring transmission line right-of-way and the line in question was ordered deenergized. It is anticipated that it would take one year or longer to accomplish relocation of the line in accordance with the county court order. The ruling is presently under appeal to the Texas Supreme Court.
- The second Belle River-Jewell 345 kV line in Michigan is necessary to deliver power from the new Belle River Power Plant to the system. Without this line, restrictions in power transfers from Ontario Hydro to Michigan are required during certain circuit outages and adverse weather conditions. Application for a construction permit was made in January 1983 and approved by the Michigan PSC for an in-service date of July 1985. Currently, the line is held up in court action for township zoning approvals and property condemnation which is estimated to delay the completion until March 1989.
- The 39-mile Seabrook-Tewksbury 345 kV line will be needed to deliver power reliably to southern New England when the Seabrook nuclear unit comes on line. There is a high probability that the line will not be completed in time due primarily to regulatory uncertainties.
- The 41-mile Valley-Serrano 500 kV line in southern California was delayed from early 1986 to mid-1987 or later when an easement to cross U.S. Forest Service lands was challenged by the U.S. Marine Corps. The Marine Corps has claimed the transmission line would interfere with their helicopter training activities. Delay of the line has impaired reliability in a 1,100 square mile area and has limited the capability to import economy energy from Arizona/New Mexico into California.
- The Kathleen-Lake Tarpon 500 kV line in Florida was delayed when the license was not granted by the Florida Governor and Cabinet, the last step in Florida's transmission

Special Protection Systems

Special Protection Systems are designed to perform system protection functions other than the isolation of electrical short circuits. They are used to automatically reconfigure the electrical system by disconnecting generation, opening lines, shedding load, and other actions to maintain stability or control power flows on surviving critical facilities immediately following a disturbance on the system. Special Protection Systems are installed to permit higher levels of power flow on the transmission system in those instances where additional facilities cannot be justified or built or have been delayed. However, they can expose a system to greater reliability risks, since the integrity of the system depends on their correct operation.

licensing process. The project will be reconsidered when the Department of Environmental Regulation sets standards for acceptable electrostatic and electromagnetic field intensities. Florida Power Corporation has filed a court appeal on this decision.

Controlling Power Flows

Energy transfers within and between systems can have an adverse impact on systems not participating in the transactions. When many systems are interconnected, numerous parallel transmission paths are created. Although arrangements are often made for transmission service along a path between the source of an energy transaction and the point of delivery (sometimes referred to as contract path), power will actually flow over many parallel paths. Some of the power being transferred will flow through transmission lines of systems not participating in the energy transaction or transmission service agreements. This may cause overloads or interfere with the delivery of electricity to customers. Parallel flows can be limited, and to some degree controlled, by installing phase shifters or direct current systems, or by reallocating generating output at increased fuel cost.

Other ways of compensating for the effects of power flows include use of static var compensators and Special Protection Systems. Static var compensators prevent excessive voltage changes caused by power transfers. Special Protection Systems (SPS) provide a means of automatically taking remedial action for certain contingencies. Both techniques allow higher operating limits than would be possible otherwise.

SPS are complex and consist of a multitude of devices often at a number of locations geographically remote from each other. Due in large part to these characteristics, performance to date has not been as good as desired and some major outages have resulted. Improvement to such SPS applications is being pursued.

Disturbances in one part of an interconnected network can temporarily increase power flows in other parts geographically remote from the disturbance. In some cases, the reliability of systems remote from the disturbance by hundreds of miles can be more adversely affected than those in the immediate vicinity of the disturbance. The severity of the effect on the remote system depends on the extent to which the remote system is utilizing its transmission system and on the magnitude of change in power flows caused by the disturbance.

This interaction between interconnected power systems requires a high degree of coordination in planning and operation at both a regional and interregional level in order to maintain reliability.

An emerging concern for reliability is the increase in the number of non-utility generators connected to the transmission network. When a non-utility-owned generator is authorized to connect to the transmission system of a utility, the owner should be required to assume obligations similar to those a utility imposes upon its own generating facilities. The most basic of these obligations is the requirement to operate the qualifying facility generation with the minimum possible adverse effect upon transmission system reliability. Large cogenerators or a multitude of small power producers in the same area can cause reliability problems such as overloads, parallel path flow limitations, transmission system instability, voltage changes, etc. One detrimental effect on reliability of non-utility generation is also one of its advantages: the short time required for installation. Non-utility generation can be installed quickly — before adequate transmission can be constructed; therefore, reliability may fall below acceptable levels.

Financing and Regulation

Electric utilities today are quite reluctant to make commitments to major new projects because of licensing and cost recovery difficulties. This is true in both the public and private sectors of the industry. In the United States, orders for major new baseload generating units have virtually ceased. Further, in both the United States and Canada, social and political pressures to keep electric rates down have influenced public decision-making toward discouraging the building of new generating and transmission facilities. If actions are not taken in the near future to mitigate these problems, the ability of the industry to continue providing a reliable electric power supply could be severely tested.

Financing and Rates

The electric utility industry, if it is to continue to provide reliable electric service, must add and maintain facilities to keep pace with the growing needs of customers. Matters such as ratemaking, licensing, accounting procedures, and competition are becoming major influences in the decisions to invest in power systems. The influences come into play as follows:

- Utility investors must be able to anticipate returns commensurate with the risk
- Licenses to construct and operate facilities must be obtainable in a reasonable time period
- Regulatory policies must recognize and endorse reliability requirements for planning and operation

Traditionally, the costs incurred for facility expansion have been passed on to customers through the ratemaking process. Regulatory agencies generally review the prudency of large projects during the licensing procedure; but, in the last few years, some major utility costs for generating plants and transmission lines in the United States have been disallowed after project completion. Regulators have cited cost overruns and the failure of loads to grow as forecast as reasons. The effect of disallowed costs has been to shift some of the risk of planning in uncertain times to utility investors.

The Financial Accounting Standards Board has added to the effect of rate base disallowances in the United States by the proposed revision to its 1982 statement of financial accounting standards (SFAS-71). In brief, the revision requires that, if rate recovery of the costs of a utility project is disallowed, or even if there is substantial uncertainty as to whether the costs will be recoverable, the utility may not write off those costs over an extended period of time but must instead write them off immediately. The effect of this revision could be very severe for some utilities and would reduce the incentive to commit to needed new projects. Even the completion of projects already under construction could be threatened by the ensuing financial drain because the raising of capital could become extremely expensive and problematical.

Utility investors, accustomed to low risks and modest but dependable dividends, are concerned that major projects are inadvisable for investment purposes. Actions of regulators cast doubt that higher risks will be matched with appropriate returns in the future. The long lead times of eight to twelve years for large generation projects make them especially unattractive in the current situation. Utility managements, responsive to these concerns, are avoiding commitments to large projects. Only two large baseload generation projects have been committed in the United States in the last two years. The future of reliable supplies of electricity will depend on a resolution of this problem. Positive incentives are needed to spur commitments to needed facilities.

In contrast, large nuclear, coal and hydroelectric projects remain viable options in Canada and in many other countries.

Transmission

While most of the institutional threats to future reliability occur in the area of generating capacity, some involve the reliability of the transmission system. Regulatory disallowance of certain transmission facilities has discouraged reinforcements which are required to maintain reliability.

One U.S. utility has completed a major transmission line for energy imports and signed long-term contracts with obligations to take and pay for the energy. However, due to reductions in the cost of oil, electricity could now be generated locally for less than the cost of the line and the purchase agreements. Currently, the utility has been allowed to recover in rates only the alternative cost of using oil, and must take a loss on the line and contracts. The utility is understandably reluctant to initiate any new transmission projects.

In reviewing proposed transmission projects, many regulatory commissions are focusing on the cost savings, often to the exclusion of reliability benefits of the lines. In addition, some commissions require virtual assurance that even the economic benefits will be realized. Not only are such attitudes threatening to reliability in themselves, but they indirectly affect future

reliability by deterring transmission additions. It is important that regulatory bodies recognize the need to meet regional reliability criteria; it is equally important that utilities convince their commissions that such criteria are valid.

There is growing interest in achieving access to utility transmission systems by non-utility power producers. Some are seeking to wheel power to the utility having the highest avoided cost. Others, such as industrial cogenerators, wish to serve loads at locations remote from the generating site. Both wish to use the transmission systems of intervening utilities. To maintain reliability, a utility should have control of its system. If wheeling interferes with this control, the system operator's ability to respond in the event of an emergency will be compromised, and reliability may suffer.

The costs of using existing transmission facilities should be proportionately shared by the utility owning the facilities and any third parties who wish to wheel power over them. The costs should include both the cost of replacement of the facilities and the value gained through the use of them. If third party access means that some reinforcement will be required earlier than would otherwise have been required (if at all), an equitable sharing of the costs of the addition should include the third parties. If it does not, the utility and its large pool of customers in effect subsidize the third parties.

Operations

The job of the system operator is to maintain system reliability while minimizing operating cost. Faced with a future environment of more closely interconnected systems, new control devices, direct current transmission and other advances, a new set of challenges is arising for the operator. A higher level of training, education, communication and control will be required to meet those challenges and maintain the existing level of reliability.

Previous sections of this report have dealt with the system planning of future facilities. This section will discuss the responsibilities of the system operator and changes in system operation that can be foreseen for the next decade.

The Operator's Responsibilities

Electric generation and transmission facilities are interconnected to form a complex system which must be carefully monitored and controlled by the system operator on a minute-to-minute basis if reliability and economic operation are to be achieved. The basic objectives of system operation are twofold and are sometimes conflicting — i.e., achieving adequate reliability and minimizing cost of operation. The system operator continuously balances these objectives. An adequately designed and constructed system can provide reliable economic electric service when properly operated.

The system operator's control of a system is achieved through:

- Scheduling the loading and maintenance pattern of the system generation and transmission facilities using security, economic and maintenance considerations
- Preparing for responses to reasonable emergency conditions so as to keep the risk of customer interruption to an acceptable level
- Maintaining a proper minute-to-minute match between generation and customer demand
- Assessing and evaluating past operations

Preparedness

Operators prepare for secure future operations by scheduling generation and transmission capacity along with interchange transactions and fuel supplies so that system resources will be adequate to withstand outages of a reasonable number of facilities. The accuracy of short-term load forecasts for system operations is a keystone in this preparation. Some important aspects of system operations are:

- **Emergency Operations** — The system operator must be prepared to respond to outages of generation or transmission facilities and to recover from the effect of those outages in a reasonable time, including the rapid restoration of customer load. Some of the tools used for this activity are communications, generation and transmission reserve, load shedding, assistance from other systems and written operating procedures.
- **Plan for Large Energy Transfers** — Utilities use their transmission networks to transfer large amounts of electricity between systems to achieve economies, but may do so at some detriment to reliability. In planning ahead for these transfers, system operators develop strategies for preventing overload or voltage collapse should facility outages occur.
- **Fuel Management and Maintenance Scheduling** — Adequate reliability requires a reserve fuel inventory and the timing of equipment maintenance outages so that unforeseen conditions will not result in customer interruptions. Fuel inventories and maintenance outages of key facilities can be extremely expensive. There is pressure on the operator to minimize the cost, sometimes at the expense of reliability.
- **Training and Education** — The use of new technology is bringing with it the need for more intensive training and specialized education of the personnel in system operations. More information about the system is being brought into the control centers, and is being used by sophisticated computer systems to assist the operator in making quick decisions regarding reliability and cost. System operating personnel of the next decade will be required to have higher education levels and specialized training to apply new developments properly.
- **Coordination** — A basic strength of interconnection and system operation is the sharing of knowledge among system operators and other electrical industry groups. Over the years, the exchange of information has expanded to involve system operators, system planners, power plant operators, system protective relay groups, telecommunication groups, and transmission maintenance personnel. Extensive transmission development, particularly in the central and eastern portions of the United States and Canada has brought the utilities closer together electrically. As a result, power

transfers and disturbances are affecting utility operations across wide areas. Consequently, operators are expanding the collection of data and communication systems to encompass more areas.

Control

System operators depend on other systems, with which they are interconnected, for support in achieving the highest reliability of their own systems. Being a participant in the interconnected system carries with it the obligation to control transmission power flows, voltages and frequency within established limits. Adequate and reliable information systems are making full use of the capabilities of new technology to assist system operators in reaching correct conclusions about their system's condition. Some specific parameters requiring careful control are:

- **Interconnection Loading —** Each system operator is responsible for scheduling generation loading so that internal requirements will be continuously met and interconnection flows are held to the scheduled amounts.
- **Frequency Control —** All interconnected alternating current systems must operate at the same frequency. A frequency above 60 Hz results when generation exceeds demand, while a drop in frequency below 60 Hz will occur when the generation is less than the demand. The control of frequency is achieved by adjusting generator output power in a coordinated manner with careful regulation by all system operators.
- **Power Plant Operation —** Good power plant response to the system power needs is vital to interconnected systems reliability. System operators and plant operators work together to enhance this response. An impressive effort is being made on many systems through improved operating and maintenance procedures to increase the capability and availability of existing generating units.

Assessment and Evaluation

Successful operation is aided by review of past operating performance and by constructive criticism of operating procedures by other operators. The NERC Operating Committee provides expertise to help evaluate the systems' conformance to the NERC policies and procedures.

Future Operations

The environment in system operations is changing with innovations such as non-utility ownership of generation, high voltage dc transmission equipment, high speed control devices, static var controllers, and transmission access.

Training will be needed to prepare the system operator to deal with the future system. Operating policies and procedures are under continuing review taking into account new technology and input from experienced utility operators. System operators will use new scientific developments as they become available in the computing, telecommunications and other areas. Studies are ongoing in the field of interconnection dynamics, new control facilities, parallel flows, dc transmission, voltage control, and load shedding.

This changing environment, plus the reduced capacity margins that are presently forecast for the ten-year period of review, will require the system operator to adapt. With the timely installation of modern facilities, improved training, modern simulation techniques and up-to-date operating policies and procedures, a balance between reliability and the cost of operation can be maintained.

ECAR

East Central Area Reliability Coordination Agreement

The ECAR Region will have an adequate and reliable power supply throughout the 1986-1995 review period provided that the equivalent availability of generating equipment remains at or near recent levels and generation and transmission additions are completed as scheduled. By 1995, ECAR's capacity margin will be approaching the minimum level required to serve the projected loads in a reliable manner.

The overall reliability of the Region could degrade to an unacceptable level near the end of the review period if availability of generating equipment should decrease significantly, if acid rain control strategies are implemented which result in significant existing capacity derating or if there are delays in planned generation and transmission additions.

	Actual		Forecast		
	Summer / Winter	1985 / 1985/86	1986 / 1986/87	1995 / 1995/96	Growth Rate (%/year)
Summer Peak MW		66,293	68,356	82,217	2.1
Winter Peak MW		65,667	67,355	81,079	2.1
Annual Energy GWh		387,514	389,000	469,400	2.1
Installed Capability (summer) MW		92,960	96,452	103,454	0.8

Demand Projections

The aggregate of the demand projections provided this year by systems in ECAR shows that the Region is expected to be summer peaking throughout the 1986-1995 period. The average annual growth in projected peak demand for the period 1986-1995 is approximately 2.1% for both summer and winter, rates which are approximately the same as one year ago. However, the current projection for the 1986 summer peak demand (68,356 MW) is approximately 2% lower than last year's projection for the same season. The result is that the load level projected for each of the years during the period is somewhat lower than the level projected last year. Projected annual energy requirements exhibit a similar growth trend.

Resource Additions

Three nuclear units totaling approximately 3,200 MW are scheduled to be placed in service during the 1986-1987 period. Of the 4 major coal-fired units in an advanced stage of construction (approximately 2,400 MW), 3 were completed during the first half of 1986 and the fourth is scheduled for completion in late 1988. These 7 units constitute approximately two-thirds of the projected major capacity additions during the review period.

There are no major capacity additions scheduled in 1989 or 1990. During the 5-year period 1991-1995, only 4 coal-fired units (1-300 MW, 1-495 MW, 1-600 MW, 1-1,300 MW) are projected for the entire Region. Construction has been started on 3 of these 4 units, but the potential exists that 1 or more could be either deferred or canceled. The schedule for the Perry 2 nuclear unit (1,179 MW) is still under review and it is not included as a capacity addition during the period covered by this year's report.

During the 1992-1995 period, 1,235 MW of combined cycle and combustion turbine installations are projected to be placed in service. This is approximately 100 MW more than appeared in last year's projections.

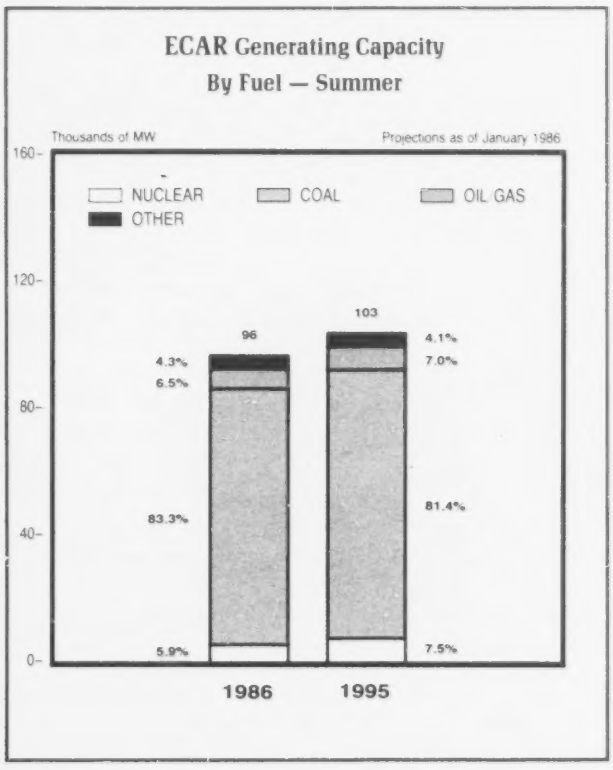
Adequacy of Projected Generating Capacity Margins

Extensive appraisals of the adequacy of projected generating capacity margins have been carried out for the ECAR Region based on probabilistic techniques and procedures. The major

input parameters for these appraisals are the regional load pattern, the status of scheduled generating unit additions, the projected planned maintenance of generating units and the random unavailability of generating equipment.

ECAR members recognize that maintaining or improving availability of generating equipment is essential if the capacity margins currently projected for future years are to prove adequate. In this regard, the equivalent availability of generating capability in ECAR for the non-holiday weekdays during the year has improved from a low of 68% for 1978 to over 77% for 1985. This increase reflects the impact of improvement programs; however, over the next 10 years it will be increasingly difficult to maintain power plant availability at the favorable high levels experienced in recent years. First, the capacity margins will decrease over the period causing installed capacity to be worked harder. Second, the generating capacity is aging. ECAR systems plan to operate their older plants well beyond the normal retirement dates and by the end of the period, approximately 27% of the generating capacity in ECAR will be 30 or more years old. Environmental restrictions and any mandated additions of emission control equipment could further degrade the availability of generating equipment.

The 1986 ECAR appraisal shows that if the projected load and capacity conditions materialize, the ECAR criterion for judging the reliability and adequacy of the projected installed generating capacity will be satisfied throughout the 1986-1995 period as long as the equivalent availability is about 73% or greater.



Impact of Proposed Acid Rain Legislation

In recent years, ECAR has prepared assessments of the effects that proposed acid rain legislation would have on reliability and adequacy of bulk power supply in the ECAR area. Because of the great uncertainty about the final regulations which might be promulgated and the wide variation in possible control strategy alternatives, scenarios have been developed that would provide results which encompass the probable range of the impact on reliability.

The scenarios developed for the current assessment assume that ECAR-wide sulfur dioxide emission levels must average either 2.0 or 1.2 pounds per million BTU during calendar year 1995 (the latest year for which detailed study data were available). Strategies for achieving the desired total emission reduction were to either rely primarily on switching to low sulfur coal or retrofit as many units as necessary with Flue Gas Desulfurization (FGD) equipment.

The results indicate a very adverse effect on the adequacy of ECAR generating capacity margins. In order to maintain a reliability level comparable to that provided for 1995 by the current 10-year plan, 5,000 to 8,000 MW of additional new generating capacity would be required if the limit for the average ECAR-wide sulfur dioxide emission level was set at 2.0 pounds per million BTU and 8,000 to 10,000 MW if set at 1.2 pounds per million BTU. This capacity would be needed to offset the negative effects of lower availability of generating units due to the addition of FGD equipment and to replace capacity which would be lost because of either premature retirement or additional auxiliary power requirements associated with necessary plant modifications. This additional capacity requirement represents an increase of between 50 and 115% over the generating capacity additions already scheduled during the 1986-1995 period. It is based solely on achieving the targeted sulfur dioxide emission reduction. There is no provision for replacement of any additional loss of capacity attributable to proposed nitrogen oxide emission reduction requirements. Since lead time and capital constraints would undoubtedly preclude installing this additional capacity, reliability would be degraded.

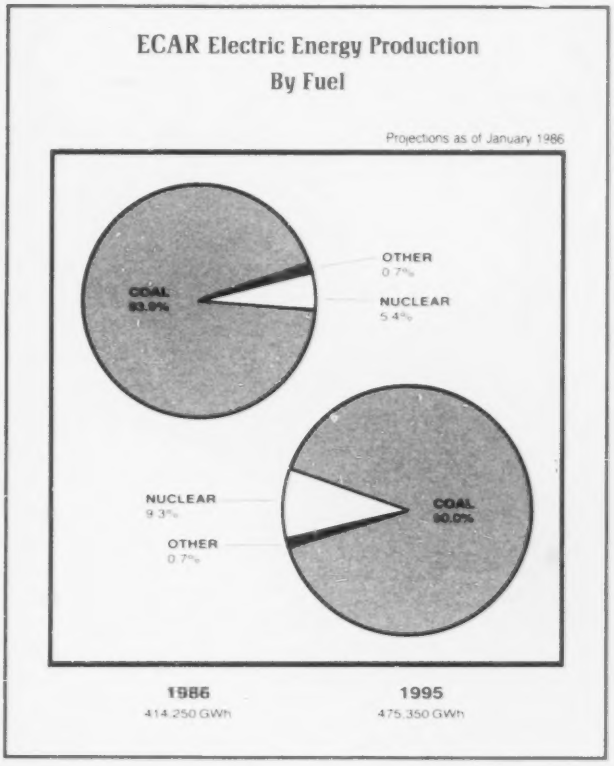
Energy and Fuel

Coal is projected to continue to be the predominant energy generation source for ECAR over the next ten years, while nuclear is projected to increase its share of total energy generation, as seen in the accompanying charts.

The high dependence of ECAR member systems on coal-fired generation makes it imperative that continuity of future coal supply be maintained and that systems be permitted to burn the significant quantities of coal needed to satisfy the future electric energy requirements in the Region.

The availability of materials and services for the various phases of the nuclear fuel supply cycle (uranium conversion, enrichment and fabrication) will continue to be adequate to meet

requirements in ECAR for the foreseeable future. However, the issues involving spent fuel storage and disposal must still be resolved.



Transmission System

The pattern of growth for the systems in the ECAR Region has led to the development of an extensive and reliable high voltage transmission network that is interconnected with the networks in neighboring regions at various voltage levels. The EHV portion of the network in ECAR consists of over 1,900 miles of 765 kV, over 800 miles of 500 kV and over 11,700 miles of 345 kV transmission.

The ECAR member systems have developed plans which call for the addition of approximately 100 miles of 765 kV, 100 miles of 500 kV, and 600 miles of 345 kV transmission during the 1986-1995 period. The addition of these facilities will create a number of new interconnections between systems within ECAR and between ECAR systems and those in other regions.

Public opposition and governmental siting requirements cause difficulty in obtaining rights-of-way and can influence the timely installation of new transmission. If it becomes necessary to defer or cancel a number of planned major additions, the reliability of the bulk power supply in the ECAR Region will deteriorate.

In recent years, the fuel cost differentials between the coal-fired generation in ECAR and the oil-fired generation located to the east of ECAR created additional opportunities for economy transfers. In addition to the long duration energy transfers scheduled well in advance, significant amounts of energy transfers have been arranged on a daily and even hourly basis between and among ECAR systems and systems in other regions. Such transfers have become an important consideration in the operation of the interconnected transmission network. Multi-party economy transfers have caused flow patterns that were not anticipated at the time the systems which comprise the network were originally planned. Some portions of the bulk transmission network have routinely been subjected to significant changes in both the magnitude and direction of the energy transfers. It is anticipated that these transfers will continue to be significant in the future and are likely to increase.

Transmission system performance studies are conducted by ECAR to assure that the system can meet regional reliability criteria. Through such studies, coordination procedures and operating guidelines are being developed and improved to assure that the interconnected network will be operated in a reliable manner.

Operations

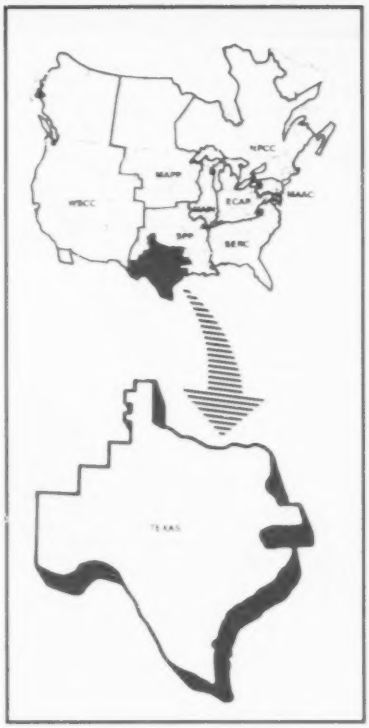
Extensive intersystem and area communication facilities are used by ECAR and its members to coordinate normal and emergency system operation among and between the individual power control centers within ECAR and with neighboring regions. The communication/computer network, which interconnects the power control centers and the ECAR office, is used to exchange operating information among the systems and to quickly disseminate to all systems abnormal condition reports (i.e., a sudden loss of generation, the tripping of an important transmission line, or the cause of an unusual transmission system loading pattern).

Several systems are in the process of designing or constructing control centers that will incorporate system security procedures and analytical capabilities to provide operators with the ability to carry out on-line evaluation of system security. ECAR systems, in conjunction with the systems in MAAC, NPCC and SERC, are actively studying the concept of computer-to-computer data links for the exchange of real-time system data and to determine cost effectiveness. Implementation of such communication links could greatly expand the base of information available to evaluate on-line system performance, taking into account multi-system operating conditions.

The East Central Area Reliability Coordination Agreement (ECAR) consists of 18 member systems which serve all or parts of the states of Michigan, Indiana, Kentucky, Ohio, West Virginia, Virginia, Pennsylvania, Maryland and Tennessee.

ERCOT

Electric Reliability Council of Texas



Projected capacity margin in the Region varies from 16.8% (1986) to 21.6% (1988), based on present unit installation schedules and load forecasts during the 10-year period. Member systems are continuing to install new generating capacity, are contracting for cogeneration, and to help limit demand growth, are implementing load management programs. Projected capacity margins meet the requirements adopted by the Region, and reliability is expected to be adequate during the 1986-1995 period.

	Actual		Forecast		
	Summer	1985	1986	1995	Growth Rate
	Winter	1985/86	1986/87	1995/96	(%/year)
Summer Peak — MW		38,062	38,957	53,052	3.5
Winter Peak — MW		29,776	31,574	47,120	4.5
Annual Energy — GWh		190,758	194,821	277,404	4.0
Installed Capability (summer) — MW		43,829	43,414	58,767	3.4

Demand and Energy

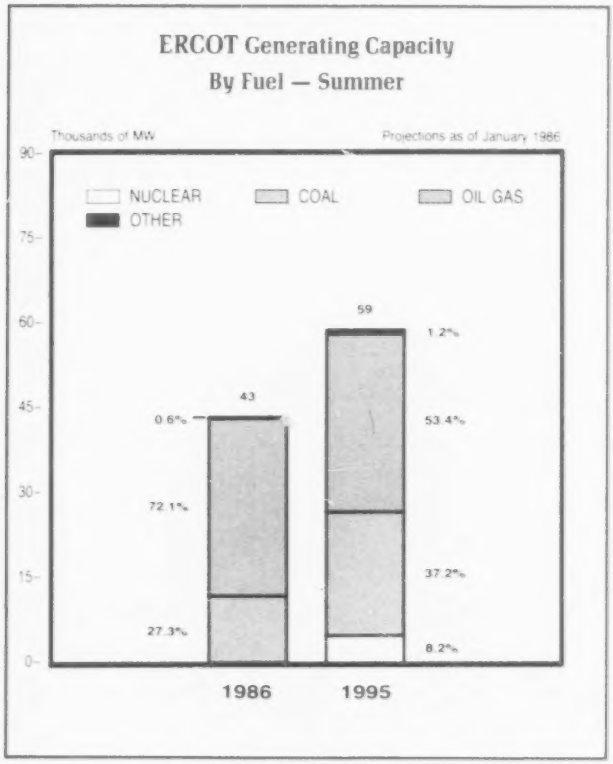
The summer peak hour demand forecast by ERCOT member utilities indicates a growth rate through 1995 averaging 3.5% per year, which is the same growth rate as that projected last year. Winter peak hour demand is forecast to grow at 4.5%, indicating the possibility of becoming a winter peaking system sometime after the year 2000. Two member systems are already peaking in the winter. Aggressive load management and conservation programs are being pursued by member utilities to decrease the rate of demand growth. Energy growth from 1986 to 1995 is currently estimated to average 4.0% annually.

Generating Capacity

New generating capacity scheduled for installation by ERCOT systems during the 10 years (1986-1995) amounts to approximately 17,660 MW. The total includes approximately 8,950 MW coal-fired capacity, 2,610 MW of combustion turbines, 4,800 MW of nuclear capacity, and 1,300 MW with fuel undesignated. Re-ratings of existing units are expected to total 230 MW for a gross addition of 17,890 MW. Retirements during the period are anticipated to total 2,600 MW, resulting in a net increase of 15,290 MW. The majority of this capacity (9,750 MW) is under construction, and another portion (1,460 MW) is either in the licensing process or has received regulatory approval. These figures exclude cogeneration and other sources which are expected to increase substantially during the period and, by 1995, to exceed 3,900 MW or 6% of total ERCOT resources.

Four nuclear units, two each at Comanche Peak and South Texas Project, are now scheduled to become operational in the 1988-1989 period.

Energy generation by ERCOT members is projected to be 43% coal or lignite and 56% gas in 1986; changing to 53% coal or lignite, 35% gas, and 11% nuclear in 1995. Remaining minor amounts of generation are from hydro, oil, and other resources. Imports from non-ERCOT members, plus purchases from cogenerators, will amount to 10.5% of net energy for load in 1986 and are projected to be 12.2% in 1995.



Generation Adequacy Assessment

Capacity margin in the Region varies from 16.8% (1986) to 21.6% (1988) during the 10-year period. Capacity purchases, principally from cogenerators, are being used to supplement ERCOT capacity on a short-term basis. Continued emphasis is being placed on high operational availability of generating capacity in the Region.

Key parameters linked with future adequacy in the Region are as follows:

Load Management and Conservation — Members are continuing to vigorously pursue load management and conservation programs of more efficient appliances, storage systems, and direct load control. Utilities are depending on these activities to significantly reduce demand growth in the years ahead.

Completion of New Capacity on Schedule — A balanced program of additions includes baseload coal and nuclear capacity and combustion turbines for peaking service. A large portion of the baseload capacity is under construction, and the peaking capacity has a short construction lead time. All must be installed on schedule to assure adequacy.

Availability of Existing Capacity — Maintenance programs are designed to obtain high availability from installed capacity, which is vital to reliability.

Good Operating Results from Cogeneration — ERCOT systems are depending on cogeneration as baseload capacity. Although the partnership between utilities and cogenerators is a new experience, many cogenerators have had years of experience operating their own generation. A good operating relationship, essential to reliability, is therefore anticipated.

Resolution of Transmission Issues — Certain situations in ERCOT, described more fully below under "Transmission," have the potential for affecting transmission planning in a fundamental way for many years. These situations must be resolved so that cogeneration and other transfers can be accommodated reliably in the transmission system.

Transmission

ERCOT members expect to install about 1,540 circuit miles of 345 kV lines during the next 10 years. Transfer capability has recently been increased to allow reliable transfer of cogeneration and other purchases. The 220 MW North Texas dc tie between ERCOT and SPP has been in successful operation since December 1984.

Complicating factors that will have significant influence on transmission planning in ERCOT are the following:

(1) The uncertain status of a double circuit 345 kV interconnection between Houston Lighting & Power Company, Texas Utilities Electric Company, and Texas Municipal Power Agency. In November 1985, a county court found that Houston Lighting & Power Company had abused its discretion in acquiring transmission right-of-way and the line circuits in question were ordered to be deenergized. It is anticipated that it will take at least one year or longer to relocate the line in accordance with the county court order. The ruling is being appealed.

(2) The 500 MW South Texas dc tie (a second tie between ERCOT and SPP) has encountered delay because of routing considerations and alleged health effects of electrostatic and electromagnetic fields from the 155 mile dc line. An alternate is being considered and has been proposed to FERC.

(3) The Zenith-Salem double circuit 345 kV interconnection between Houston Lighting & Power Company and the Lower Colorado River Authority has encountered continuing delay in obtaining a Certificate of Convenience and Necessity. Hearings are expected to be held concerning alternate routes paralleling existing rights-of-way, which may result in even more hearings if an alternate route is required.

The implications of these situations could have a lasting effect on the transmission planning process. Objectives pertaining to transmission planning in coming years include the following:

(1) Resolve the above three situations in such a way as to permit orderly transmission planning to proceed.

(2) Resolve questions regarding transmission access by non-utilities so as to allocate costs and benefits equitably and to provide a predictable framework for transmission planning and construction.

These objectives must be achieved in order to obtain regulatory approval of transmission needs in a timely manner and to meet the challenge of accommodating over 3,900 MW of cogeneration reliably during the 10-year period.

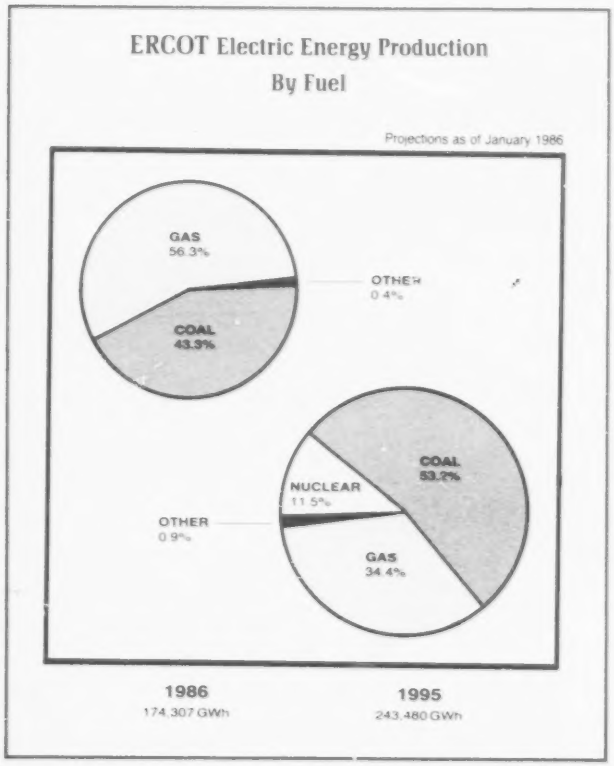
Operations

Coordination among ERCOT control areas has improved with additions to the ERCOT Operating Guides and implementation of additional enhancements to the Security Information System (SIS). One of the new Guides defines the minimum requirements for integration of a generation facility into the ERCOT transmission system; this includes cogenerators as well as utilities' generators. A second Guide provides for monthly verification of a generating unit operating capability. In addition, two technical guidelines were approved, which provide standards for metering and telemetering at interchange points between ERCOT control areas.

Enhancements to the SIS included a sharing of cost data for economy transactions to be entered and viewed via control area terminals. Other enhancements included overhaul displays for coordinating unit maintenance and a load plot display for predicting daily peaks for control areas as well as for total ERCOT. Enhancements currently under development are accounting displays, transmission outage displays, ERCOT load flow data base, and an interface between SIS and the operating load flow program.

To be prepared for the increasing complexity of system operation, ERCOT utilities have annually joined together in dispatcher training seminars. The opportunity for dispatchers to become personally acquainted and to receive common training continues to improve communication between control areas. The program this year featured discussions on weather forecasting, Security Center operation, and system generation control and interconnected operation.

Work by several task forces includes the development of ERCOT black start procedures, power transfer limits, and bias settings.



Issues

The issues of most concern to the ERCOT member systems which affect reliability are as follows:

Role of Cogeneration — Most cogenerators in Texas require baseload type operation because it is compatible with the associated industrial process and also most economical. Since this resource affects so many areas (such as capacity planning, operations, rates and economics, transmission planning, and fuel forecasting and procurement), it will have a profound impact on developments in ERCOT in future years. Central station capacity in the planning stage may be postponed as additional cogeneration ventures develop. Since cogeneration owners are basically interested in economic return, utilities who contract for such generation must assure a proper balance with reliability. Time will be required to fully assess the role of cogeneration in utility service and the effect it has on reliability.

Completion of Units on Schedule — Continued emphasis is being placed on timely completion of planned additions, as well as on high availability of existing capacity.

Lead Time for Generating Capacity — Utilities are increasingly reluctant to commit to new large units because of the long lead times involved. The uncertainty of load growth and uncertain regulatory treatment contribute to this reluctance. As a result, shorter lead time solutions such as peaking units and strategies such as phased construction of combined cycle units are being considered or used by some systems where operating conditions permit.

Transmission — Transmission development must proceed to accommodate reliably the anticipated higher transfers among systems. Those factors which delay transmission

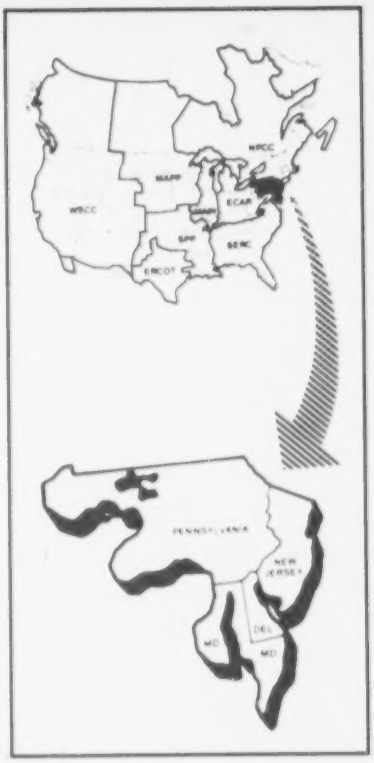
development and severely impede the transmission planning process must be resolved so that reliability can be maintained.

The Electric Reliability Council of Texas (ERCOT) is comprised of 20 municipalities, 48 cooperatives, 6 investor-owned utilities and 1 state agency. These systems operate 85% of the electric generation in Texas and serve approximately 195,000 square miles — 73% of the area of the state.

MAAC

Mid-Atlantic Area Council

Projected capacity margins and bulk power transmission capability for the 1986-1995 period are expected to be adequate to meet MAAC reliability objectives based on current demand forecasts and planned generation and transmission additions. Factors that could adversely affect reliability include load requirements exceeding forecast, delays of planned generating and transmission facility additions and unanticipated generator maintenance outages in peak periods. Disturbances caused by the sudden loss of generating sources in other regions can significantly increase power flows on the MAAC transmission system. Parallel path flows caused by energy transfers in neighboring systems also increase power flows on the MAAC system. Because of these effects, a high degree of coordination in planning and operation among MAAC and systems in neighboring regions is required to ensure that adequate reliability is maintained.



Actual			Forecast		
	Summer	1985	1986	1995	Growth Rate
	Winter	1985/86	1986/87	1995/96	(%/year)
Summer Peak — MW		37,053	36,689	40,593	1.1
Winter Peak — MW		31,652	32,742	38,590	1.8
Annual Energy — GWh		189,671	191,748	221,084	1.6
Installed Capability (summer) — MW		47,157	47,512	50,846	0.8

Demand Projections

The summer peak demand experienced by the MAAC Region on August 15, 1985 was 37,053 MW which was 1,611 MW or 4.5% above the June 13, 1984 record peak and 1,443 MW or 4.0% above the forecast. This was the third consecutive year that all-time peaks have occurred. Individual company demands exceeded their previous record peaks by 1.8% to 10.7%. MAAC energy for the year 1985 was 2.0% above the previous all-time peak year of 1984. The energy had been forecast to be 1.2% over 1984.

Actual peak demands and energy figures are shown above along with projections for 1986 and 1995.

The 1986 summer peak projection is about 650 MW higher than was projected last year for 1986 reflecting recent actual demand experience. This higher near-term demand results in an 800 MW increase in the 1994 projected demand (compared to last year's projection) even though the projected demand growth rate (1.1%) over the 10-year period remains the same as last year. Long-term energy growth is projected at 1.6% per year.

The projected summer and winter peak demand growth rates for the 1986-1995 period are shown below:

MAAC Peak Demand Forecast Growth Rate Comparison (%/Yr)		
	Last Year's Forecast ('85-'94)	This Year's Forecast ('86-'95)
Summer	1.1	1.1
Winter	1.9	1.8

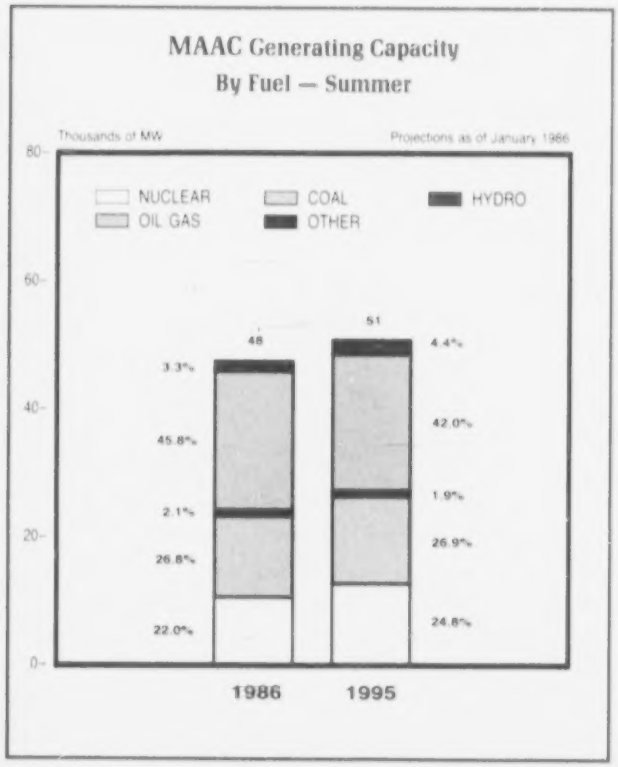
The relatively low projected peak growth rates reflect the effects of higher real energy prices, changes in patterns of consumer energy use and the effects of load management programs. The Region has traditionally been summer peaking. With winter peak loads growing faster than the summer peaks, there is a long-term trend toward becoming a winter peaking Region. The 1986 summer peak is expected to exceed the preceding winter peak by 15.9%. By 1995, the summer peak is

projected to exceed the preceding winter peak by only 6.9%. However, the Region is not expected to cross over to winter peaking until after the end of the century.

Energy Production Resources

Nuclear energy production resources have increased significantly in early 1986. TMI Unit No. 1, rated 776 MW, returned to full power operation early in 1986 after being out of service since Unit No. 2 suffered reactor damage on March 28, 1979. Limerick No. 1, a 1,055 MW nuclear unit, went into commercial operation in February 1986. This addition, in conjunction with retirements and derating of existing units, brings the existing MAAC capacity to 47,512 MW, with an installed capacity mix of 73.2% fossil, 22.0% nuclear, and 4.8% hydro.

A total of 4,194 MW of new generation is planned to be added to the MAAC systems from 1986 through 1995. These additions include 2 nuclear units totaling 2,122 MW and 2 coal-fired units totaling 940 MW. A total of 860 MW of capacity is scheduled to be lost due to retirement or derating. As now scheduled, by the summer of 1995, MAAC will have 50,846 MW of installed capacity consisting of 70.7% fossil, 24.8% nuclear, and 4.5% hydro. Approximately 65% of the generating capacity committed to be installed during the review period is well under construction.



Adequacy of Generation Resources

The capacity margins projected for the MAAC Region for the next 10 years indicate that as planned, sufficient generating capacity will be available in the MAAC Region through the 1986-1995 period to serve the MAAC load reliably. Capacity margins are forecast to range from 26% in the early part of the period to just over 20% by 1995.

The "Reliability Principles and Standards for Planning the Bulk Electric Supply System of MAAC" (as adopted July 18, 1968) states: "Sufficient megawatt generating capacity shall be installed to insure that in each year for the MAAC system, the probability of occurrence of load exceeding the available generating capacity shall not be greater, on the average, than one day in ten years. Among the factors to be considered in the calculation of the probability are the characteristics of the loads, the probability of error in load forecast, the scheduled maintenance requirements for generating units, the forced outage rates of generating units, limited energy capacity, the effect of connections to other pools, and network transfer capabilities within the MAAC system." The capacity requirement projected for the MAAC Region is developed consistent with this reliability criterion for installed generating capacity.

Factors which may adversely affect the adequacy of MAAC's installed capacity are delays in the installation of new generating capacity, lack of facilities for disposal of nuclear waste, the enactment of more restrictive regulations governing SO_2 emissions from existing electric generating plants, peak period generator maintenance, an acceleration of the trend toward a transition of MAAC from a summer to a winter peaking Region, and peak and energy demands exceeding forecast.

Approximately 1,500 MW of planned new capacity is not under construction or is less than 50% complete. If this capacity is not installed on schedule, MAAC reserves may be inadequate near the end of the review period.

Sufficient fuel is expected to be available to provide an adequate supply of energy to the Region over the review period. While the supply of nuclear fuel is judged to be secure, issues involving spent fuel storage and disposal must be resolved, particularly for older nuclear units. The passage of the Nuclear Waste Policy Act of 1982 represents a step toward resolving these issues. Continued operation of these units will be assured by meeting the stipulations of this Act within the prescribed time frame.

With a major percentage of the Region's capacity and energy requirements being produced by coal-fired and dual fuel plants in 1986, regulations which call for reduced SO_2 emissions and in turn restrict the operation of existing coal-fired plants could also severely affect the Region's system reliability. Some older coal-fired units, now part of the Region's installed reserve, may have to be retired while the output of other plants may have to be reduced. Additionally, the installation and maintenance of

any required new emission control equipment is expected to reduce plant capacity ratings and availability.

Some maintenance and refueling is now being done during peak load periods. These planned maintenance outages, together with unanticipated maintenance outage extensions, forced outages, and the unexpected high load in August 1985, left MAAC precariously low on operating reserves for a short period. MAAC was able to meet its reserve objective only by importing over 3,000 MW from adjacent systems and implementing emergency operating procedures. The forecast change in load shape after the year 2000 in the MAAC Region from summer to winter peaking is also expected to cause MAAC companies to perform additional periodic planned maintenance during peak periods. Thus, the installed capacity margin objective will have to accommodate those unit outages which cannot be scheduled for non-peak seasons.

A significant risk to the reliable operation of MAAC over the next 10 years is higher than forecast load growth. MAAC reserves may be inadequate in the early 1990's with a 1.6% per year load growth (1.1% per year currently forecast) even if all scheduled capacity is installed on schedule.

Cogeneration and Small Power Production

There is considerable potential for development of non-utility generation (cogeneration and small power producers) within the MAAC Region. Almost 1,300 MW of non-utility generation is accounted for in MAAC load and capacity projections by 1995. MAAC systems estimate that an additional 1,200 MW or more of non-utility generation, which is not now accounted for in load or capacity forecasts, could be added in MAAC by 1995. Many issues remain to be resolved to properly incorporate these generating facilities into the operation and planning of the system. The effect these facilities will have on reliability of supply in MAAC is a function of many factors, including their availability, willingness to coordinate maintenance schedules, effect on transmission systems, and effect on light load operation due to their non-dispatchability. If the facilities are installed when scheduled, remain in business and perform well as an integrated part of the supply system, reliability could be enhanced. Alternatively, reliability could be adversely affected if non-utility generation included in the forecasts is not developed, ceases operation prematurely or if the performance characteristics are substantially below those currently projected for the facilities. System reliability could also be adversely affected if the installation and operation of non-utility generation connected to a system that was not originally designed for additional generation are not coordinated with installation of required transmission reinforcements, and operation of the integrated electric supply system.

Transmission System

The MAAC transmission system is a network of 1,630 miles of 500 kV transmission lines which overlay and interconnect the network of 4,640 miles of 230 kV lines and 170 miles of 345 kV lines. Since 1982, 2,243 Mvar of capacitors have been installed on the 230 kV and 500 kV systems.

During the review period, 111 miles of 500 kV transmission lines and 294 miles of 230 kV lines are forecast to be added in the Region. One major MAAC transmission reinforcement project, the Baltimore-Washington 500 kV loop, is currently in progress. One 3-phase capacitor bank, rated 139 Mvar, is scheduled for installation on the 500 kV system in 1986 summer.

The installation of the Baltimore-Washington 500 kV loop will improve the power system stability in the Baltimore-Washington area and increase the MAAC transfer capability from the adjacent ECAR and SERC Regions. This project was originally scheduled to be completed in 1976 but has been delayed until the early 1990's due to regulatory and judicial involvement. Approximately 75% of the loop is presently in service. The two segments of the loop remaining to be completed within MAAC are the Chalk Point-Calvert Cliffs circuit and the Brighton-Waugh Chapel circuit. A conditional Certificate of Public Convenience and Necessity for both of these circuits was received from the Maryland Public Service Commission. However, the Brighton-High Ridge portion of the Brighton-Waugh Chapel circuit continued to face regulatory delays due to appeals filed with the Howard County Circuit Court. In late 1985, Howard County Circuit Court affirmed the Maryland Public Service Commission order granting the Certificate of Necessity for this line, clearing the way for obtaining the necessary zoning and/or building permits. Until this loop is completed, the Baltimore-Washington area will be exposed to reduced power system stability margins and lower import capability benefits.

With the transmission system as planned, MAAC's emergency import capability from surrounding councils and to sub-areas of MAAC is expected to be adequate through 1995.

Operations

Although accepted reliability standards are maintained, the MAAC Regional bulk power system is operated close to its thermal and reactive power limits for a significant portion of the time due to economy energy transfers. Major west-to-east transmission path utilization averaged 94.4% during 1985. The addition of nuclear units in MAAC during 1985 and early 1986, coupled with the declining coal/oil price differential due to the recent drop in oil prices, has resulted in a reduction of economy energy purchases from systems to the west of MAAC. However, west-to-east MAAC transmission capability continues to be heavily utilized for economy transfers of low cost generation in central and western portions of MAAC to load centers in eastern MAAC, particularly during daily peak load periods. Recognizing the demonstrated volatility of oil prices, the magnitude of economy energy in the future is highly uncertain. Flexibility must be maintained to respond as these conditions change.

MAAC's ability to transfer economy energy is expected to continue to be heavily used during the next 10 years as the MAAC members and adjacent systems continue to strive to maximize economy of operation. MAAC experiences substantial parallel path power flows resulting from neighboring systems making economy energy purchases, increasing the complexity of operating the MAAC system. Coordinated guidelines to address this joint system use have been developed to ensure that reliability and economy are optimized.

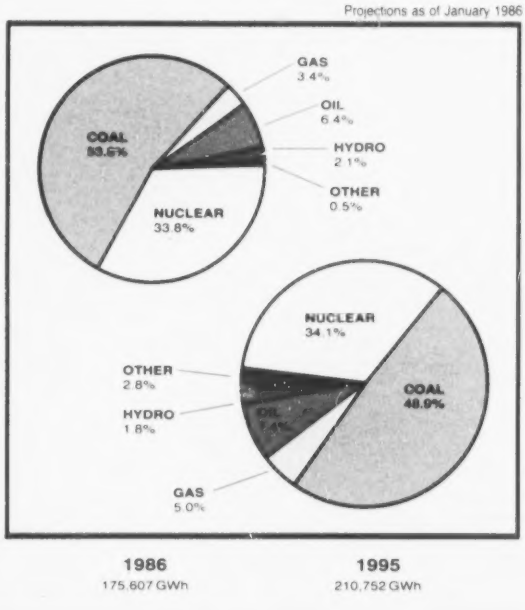
Disturbances caused by sudden loss of generating sources in other regions can have a significant impact on the MAAC transmission system. MAAC has a low impedance 500 kV transmission network with interconnections to regions to the west, north, and south of MAAC. Over 75% of the interconnected system's inertia is located to the west and south of MAAC. Therefore, outages of generating sources in systems north and east of MAAC can cause a significant increase in west-to-east power flow through the MAAC system. Since the MAAC system is operated at its west-to-east transfer limit a large portion of the time, this incremental power flow could adversely affect the reliability of the MAAC system.

The MAAC system is operated such that the more probable contingencies, even those remote from the MAAC system, will not cause thermal overloads or excessive voltage drops in the MAAC system. Because the MAAC system is affected by remote outages of generation sources, the operators must be aware of conditions both within MAAC and external to MAAC that can cause problems and know how to deal with them if they occur. This requires that the affected systems cooperate in system studies and in system operations. Such coordination has been accomplished in the past and has recently been intensified because of the concerns described above. Joint interregional studies are conducted by MAAC, ECAR, NPCC and the VACAR subregion of SERC as standard practice for operating and planning purposes. As interregional concerns have come to light, these routine studies have been directed to address the specific problems. In the case of generation source outages in New York and New England, joint MAAC-ECAR-NPCC (MEN) studies have been completed for 1986 conditions and are underway for post-1990 conditions. The MEN studies are also supplemented by others conducted outside the MEN organization. Currently, a PJM/NEPOOL/NYPP Study is underway to investigate the 1986-1990 time period. Results of other post-1990 studies being conducted by New England and New York will be shared with MAAC.

Studies to determine MAAC's ability to import economy energy from neighboring regions and the ability of MAAC and sub-areas of MAAC to import emergency power will continue to be performed on a regular basis. The purpose of these intraregional and interregional studies is to assess the present, near-term, and future performance of the interregional bulk power transmission system. System operators are alerted to potential problem areas as they are identified. System development and operating procedures are coordinated with neighboring regions to assure that the reliability of the interconnected transmission system is maintained.

MAAC has worked with NPCC to develop an operating procedure, now being tested, for sharing the activation of reserves to cover sudden large outages. Since 1978, MAAC has participated with NPCC in a computer data exchange network for the instantaneous transfer of information among operating centers in these regions. MAAC is now participating with systems from ECAR and SERC to establish a similar network.

MAAC Electric Energy Production By Fuel

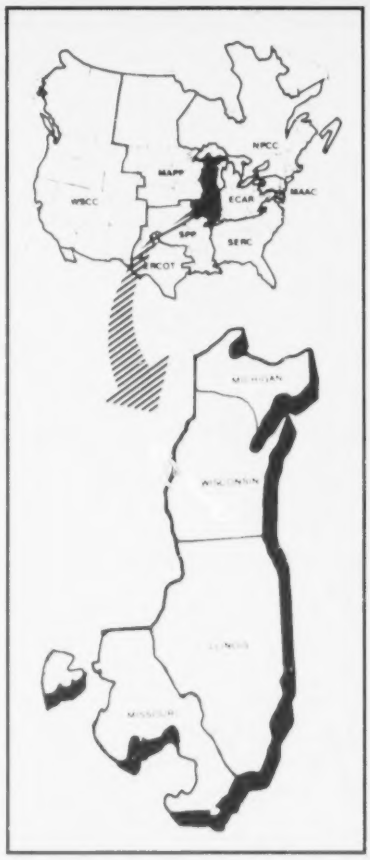


The Mid-Atlantic Area Council (MAAC) consists of 11 member systems and 5 associates serving over 20 million people over a 48,700 square mile area. The Region includes all of Delaware and the District of Columbia, major portions of Pennsylvania, New Jersey and Maryland, and a small portion of Virginia.

MAIN

Mid-America Interpool Network

MAIN will have adequate capacity for reliable power supply for the next 10 years provided that projected capacity additions are completed as scheduled. While MAIN utilities are concerned about their ability to react fast enough in the event demand grows faster than forecast, a greater concern is the possibility that some as yet unknown factor might affect MAIN's ability to complete the generating plants now under construction. Nuclear plants make up 88% of that construction program. MAIN utilities see no reason why these plants should not be completed on schedule. MAIN's capacity margin would be inadequate by 1992 if none were completed. Since coal is a major fuel in MAIN, another major concern is the unknown effect of possible regulatory actions dealing with acid rain.



Actual			Forecast		
	Summer	1985	1986	1995	Growth Rate (%/year)
	Winter	1985/86	1986/87	1995/96	
Summer Peak — MW		32,432	35,752	40,940	1.5
Winter Peak — MW		29,060	28,953	34,661	2.0
Annual Energy — GWh		173,589	177,114	207,358	1.8
Installed Capability (summer) — MW		44,568	45,334	50,222	1.1

Demand and Energy Requirements

In 1985, MAIN had a summer peak demand that was 7.8% below that of 1984 and 7.7% below forecast. The low peak demand was probably due to the relatively cool summer in part of the Region. The use of electricity in MAIN increased by 1.6% over 1984 and was 0.6% above forecast.

In 1986, MAIN utility forecasters are forecasting an average annual growth rate of 1.5% per year for the 10-year period. This is down slightly from last year's estimate of 1.6% per year. The current forecast of 1994 summer peak demand is only slightly less than last year's forecast for 1994.

It is possible that demand might be either more or less than the forecast values if conditions develop differently from that now expected. Utilities and regulatory agencies are placing greater emphasis on programs to encourage conservation, load management, cogeneration, etc. Some of the MAIN utilities have based their need for new capacity on assumptions about the success of these programs. The degree of success of these programs (which is difficult to predict) will affect the need for new generation. These new programs add one more uncertainty into the load forecasting process. MAIN forecasts are intended to have an equal probability of being high or low. The effects on reliability, however, are far from equal for actual peak demands higher or lower than forecast. The present inability of utilities to site, license and construct new generating capacity in a timely manner results in a greater risk to reliability if current forecasts are too low. If forecasts are too high, planned facilities can be deferred (although this could impact costs) and reliability is not jeopardized.

Adequacy of Generation Resources

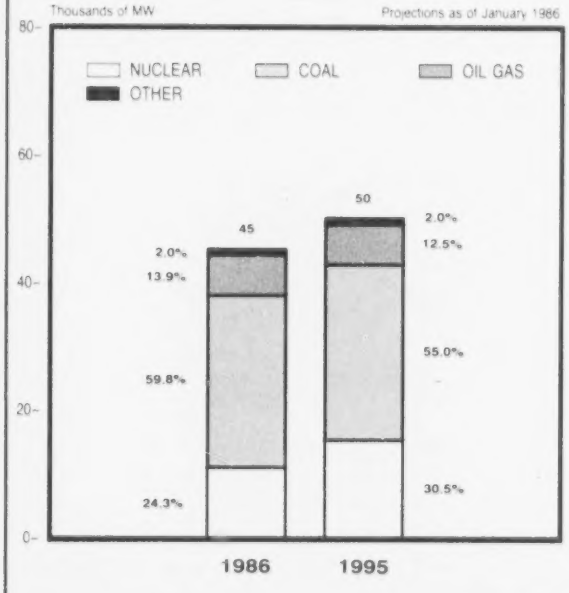
In the 1986-1988 period, four nuclear units are expected to be placed in commercial operation. Generating capacity margins in MAIN will be above the minimum levels required for reliability for several years after these large units are completed.

Present analysis suggests that MAIN members should maintain an installed generating capacity level of at least 15 to 20% above forecast peak load. (This is equivalent to a capacity margin of 13 to 17%.) Margins will be above minimum during the 10-year period with demands as forecast and capacity as planned. This situation offers several advantages. With ample margins, economical replacement power will be more readily available within each system or from others in the Region. Because returning a unit to service after an outage is not as critical as it is when margins are closer to minimum levels, maintenance can be performed more economically. Also, in most MAIN systems, peak load and energy requirements can be met by using reliable low-cost coal and nuclear generation. The availability of low-cost generation also provides opportunities for sales to other areas to displace oil- and gas-fired generation.

No major units are planned for completion in MAIN during the 1989 to 1995 period. Nevertheless, generating capacity in 1995 will be able to supply the peak demand forecast for that year with an acceptable capacity margin.

With construction of new baseload capacity now requiring a lead time of 8 or more years, a slight increase or decrease in forecast demands could result in premature or belated installation of generation units. A utility's ability to cope with even relatively small, unexpected increases in the rate of growth is severely limited by the long lead times of new generating capacity. Even relatively short lead time capacity such as combustion turbines can now take as much as 5 years to site and construct. Adequacy could be seriously reduced if significant growth in demand not now forecast occurs by the early 1990's.

MAIN Generating Capacity
By Fuel — Summer



Major Factors Influencing Adequacy

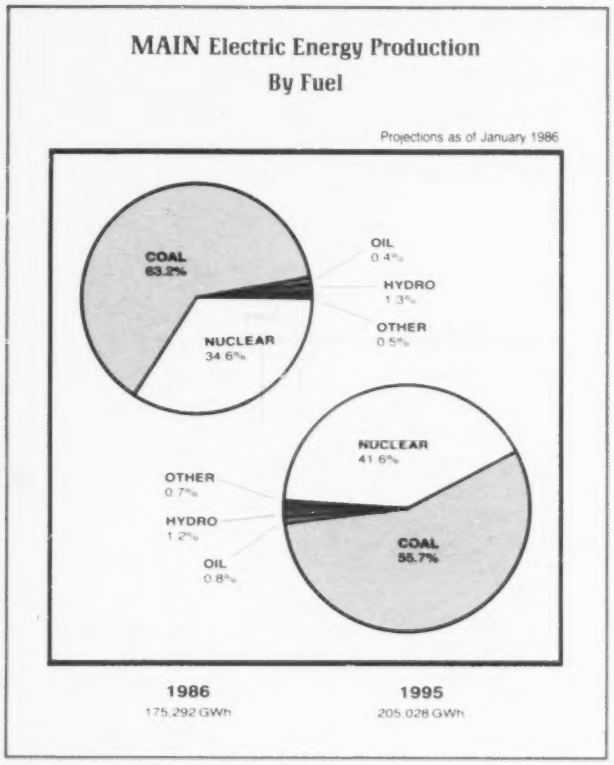
The most critical factor influencing adequacy in MAIN is the ability to complete the 4 nuclear plants which represent 88% of the capacity addition program. In 1994, nuclear plants are projected to provide 42% of MAIN's energy. If, for some reason, none of the units under construction (and which owners at this time expect to finish) were completed, capacity could be inadequate as early as 1992.

Since coal is the major fuel in MAIN, possible regulatory actions dealing with acid rain may have a major effect on MAIN utilities. In addition to the concern for the cost of meeting possible requirements of reduced SO_2 emissions, reliability of supply to the MAIN Region may be adversely affected. The maximum output of existing coal units would be somewhat reduced if retrofitted with emissions control facilities. The average availability of retrofitted units may also decrease. It may not be possible or economic to retrofit flue gas desulfurization equipment on older units, thus causing premature retirement. These factors would tend to reduce the capacity available from existing coal units. If new regulations are developed, the cost and lead time for possible replacement capacity must be given suitable consideration.

As a positive step toward emission reduction, Wisconsin Electric Power intends to convert the 4 pulverized coal boilers in its North Oak Creek plant (420 MW) to atmospheric fluidized bed combustion for service in 1992 through 1994. They intend to convert Port Washington Unit 5 (75 MW) to pressurized fluidized bed combustion. Replacement with new fluidized bed equipment will also restore 60 MW of capacity which is now unavailable because of derating of present boilers.

Transmission

Economy transactions among MAIN utilities and between utilities in MAIN and surrounding regions have increased over the years. As a result, some sections of the interconnected transmission system are being loaded to allowable limits during part of the year. This increases the probability that transmission line outages may result in interruption of service to customers. Reliability criteria are still being met, but transmission margins are less than they have been. Delay of committed transmission projects would increase this vulnerability.



Operations

Utilities are countering the greater risk being caused by increased economy transfers and more extensive loading of the transmission system by providing additional operational capability and increased operator preparedness. A new computer facility has been approved for installation at the MAIN Coordination Center to improve the effectiveness of monitoring the bulk power system. This will be a first step in the eventual replacement of the communication system that was installed in 1980. In addition, work is underway to improve individual system control centers, to provide operators with more and better information on the current state of the power system, and to provide for continued and more extensive operator training.

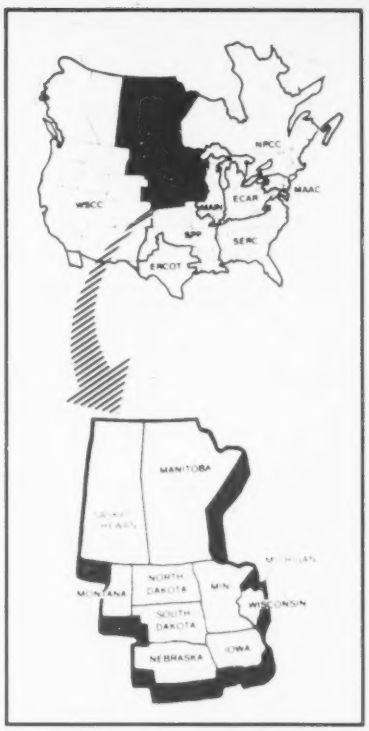
The Mid-America Interpool Network (MAIN) consists of 13 regular member systems and 1 associate member. MAIN is a summer peaking Region containing Illinois, the eastern third of Missouri, the eastern two-thirds of Wisconsin and most of the Upper Peninsula of Michigan.

For reporting purposes, MAIN is divided into four subregions: Commonwealth Edison Company, the balance of Illinois, East Missouri, and the Wisconsin-Upper Michigan System.

MAPP

Mid-continent Area Power Pool

Capacity margins for the 1986-1995 period will meet present MAPP reliability criteria. The transmission system within MAPP is capable of supplying firm power requirements, with sufficient capability for scheduling significant emergency and economy energy transfers.



Actual			Forecast		
	Summer	1985	1986	1995	Growth Rate (%/year)
	Winter	1985/86	1986/87	1995/96	
MAPP — United States					
Summer Peak — MW		19,936	21,541	25,386	1.8
Winter Peak — MW		18,803	19,269	22,760	1.9
Annual Energy — GWh		105,797	108,923	131,469	2.1
Installed Capability (summer) — MW		28,685	28,750	30,205	0.6
MAPP — Canada					
Summer Peak — MW		3,874	4,011	5,103	2.7
Winter Peak — MW		4,950	5,547	6,862	2.4
Annual Energy — GWh		26,724	27,547	35,177	2.8
Installed Capability (winter) — MW		6,589	6,595	8,727	3.2
MAPP — Total					
Summer Peak — MW		23,810	25,552	30,489	2.0
Winter Peak — MW		23,753	24,816	29,622	2.0
Annual Energy — GWh		132,521	135,470	166,646	2.3
Installed Capability (summer) — MW		35,064	35,381	38,968	1.1

Demand and Energy Projections

The MAPP demand and energy forecasts are the sum of the individual MAPP member forecasts. The United States portion of the MAPP Region is summer peaking and had a non-coincident summer peak of 19,936 MW in 1985. This demand was 3.5% below the 1984 peak and 9% below the forecast. Energy was 0.4% above the 1984 actual amount. The Canadian Provinces which are associated with MAPP are winter peaking and had a non-coincident peak demand of 4,950 MW in the 1985-86 winter season, essentially the same as the 1984-85 winter peak.

Summer peak demand and annual energy of the MAPP Participants are estimated to increase at average annual rates of 1.8% and 2.1%, respectively, in the 1986-1995 period. These

projections are somewhat less than the previous year's forecast of 2.2% and 2.5%, and result in the 1994 peak demand projection being 5.9% (1,582 MW) less than was forecast last year. Reasons cited for the decreased forecast within MAPP are the depressed farm economy and the decrease in the taconite industry's electric service needs. Utilities within MAPP are pursuing load management programs with more than 1,500 MW of load management planned by the early 1990's.

Resource Additions

No new generating units were placed in service during 1985. Generation additions committed or proposed by MAPP Participants for the 1986-1995 period include 3 large fossil units totaling 1,750 MW. One large coal-fired plant (650 MW) which was scheduled for commercial operation in 1995 has been canceled.

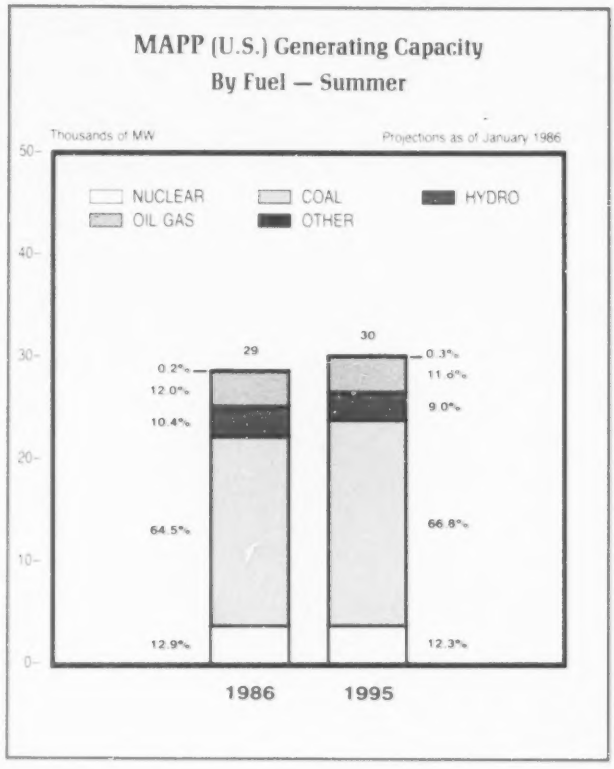
Only small amounts of generation from renewable resources, such as wind, solar, and biomass, are anticipated in this 10-year period. Smaller unit additions, unit retirements, upgrades, and derates which will take place during this period have the net effect of increasing capacity by 250 MW. The MAPP-U.S. capacity mix for 1985 and forecast for 1995 is shown in the following rounded tabulation:

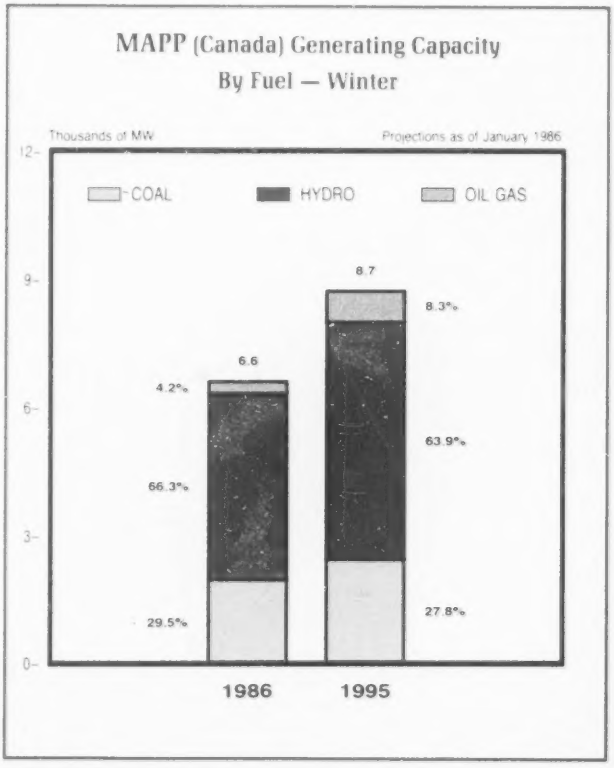
	1985		1995	
	MW	%	MW	%
Coal	18,500	64	20,200	67
Nuclear	3,700	13	3,700	12
Renewable Resources: Hydro, Wood, and Refuse	3,100	11	2,800	9
Gas/Oil Peaking	3,400	12	3,500	12
TOTAL	28,700	100	30,200	100

Because of reduced load projections, some utilities within MAPP are selling portions of existing units which allows other systems to forego construction of new generation. Although loads in locations different than that originally planned are being served by this generation, no adverse transmission reliability effects are foreseen.

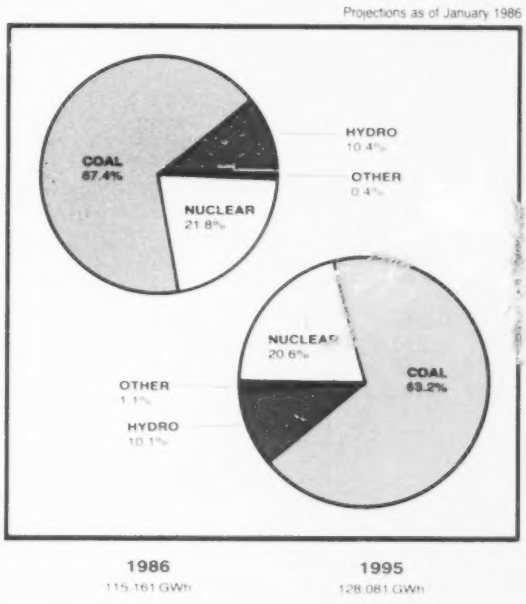
Cogeneration and small power production facilities included in the above capacity account for 21 MW in 1986 and 160 MW in 1995. An additional 23 MW of non-utility capacity is anticipated to be in service by 1995.

The Canadian Provinces associated with MAPP are adding 252 MW of hydro capacity in 1986, and an additional 1,200 MW of hydro capacity by 1993. Coal-fired capacity is scheduled to increase 482 MW by 1995 and 450 MW of combustion turbines are planned during the period 1986 to 1989. The installed capacity for the Provinces will increase from 6,589 MW in 1985 to 8,727 MW by 1995.

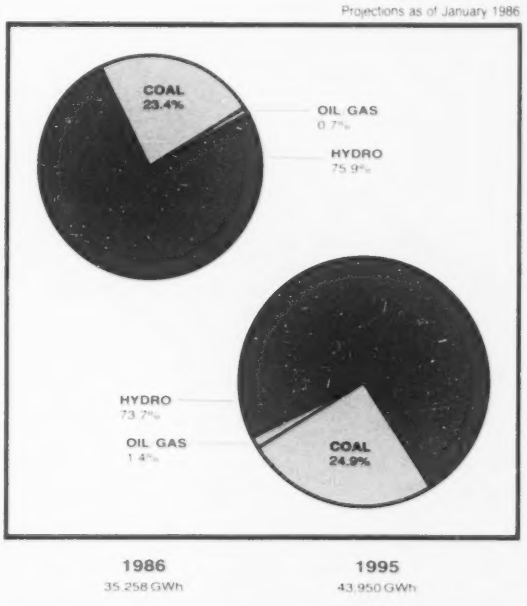




MAPP (U.S.) Electric Energy Production
By Fuel



MAPP (Canada) Electric Energy Production
By Fuel



Generation Adequacy

Reliability studies and experience of systems in the MAPP area indicate that each Participant should maintain a capacity level at least 15% above its annual peak load to provide the same level of reliability of power supply experienced in the early 1970's. (This is equivalent to a 13% minimum capacity margin.) The 1970's was a period of demonstrated reliability within the Region. A study is currently underway to determine if this is still the appropriate capacity margin for MAPP.

Historically, within MAPP there has been a diversity of about 6% in summer peak demands of the individual Participants. This suggests that the MAPP Region should maintain a capacity margin of about 18%, based on the Region's coincident peak demand. Under a MAPP service schedule, interruptible loads which are properly certified may remain uninterrupted on system peak, provided an energy supply can be found from other MAPP energy suppliers. Under this plan, the interruptible load component, for which an energy supply is purchased, will not be included in the utility capacity margin calculations.

With the committed unit additions, capacity margins for the 1986-1995 period will meet present MAPP reliability criteria.

Legislative efforts to reduce sulfur dioxide emission from power plants in an attempt to mitigate the effects of acid rain are of continuing concern to MAPP members. Addition of emission-control equipment will reduce the power available from the units on which it is installed, will increase maintenance time, and could result in early retirement of older units because of the high cost of installation and operation of a retrofit.

Transmission Issues

The MAPP utilities have 19,916 miles of transmission 230 kV and above in service and plan to build 2,350 miles of transmission 230 kV and above by the end of 1995. The MAPP transmission network is capable of supplying firm power requirements with enough transfer capability for scheduling significant amounts of emergency and economy energy. In general, intraregional transfer capabilities are adequate for reliability.

Utilities in Minnesota and Wisconsin have signed a memorandum of understanding to purchase 550 MW of electricity from the Manitoba Hydro-Electric Board beginning 1996 through 2012. The agreement is contingent upon the Canadian utility building a power line from the Winnipeg area to the U.S. border and the United States utilities building a power line from that point to their service areas.

Operations

The MAPP utilities have several programs and procedures that provide the operator with support in completing his job.

MAPP

Included are an extensive MAPP System Operator Training program, established emergency replacement procedures, transmission line loading relief procedures, and a procedure to optimize economy transactions. In addition, MAPP has embarked on a project to modernize and expand its computerized communications system to improve data collection, modeling, and communications among the Participants and with neighboring regions.

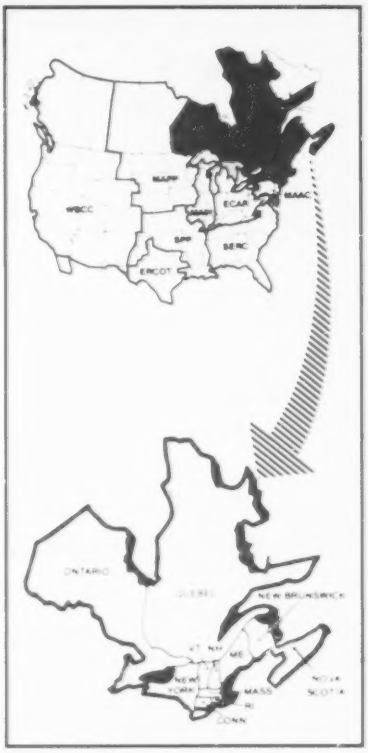
The Procedure to Optimize Economy Transactions (POET) has brought pool-wide savings of $3.3 million during 1985. POET assists MAPP Participants in arranging economy transactions each hour, which supplement normal economy interchanges among pool systems. Another procedure, the Before-the-Fact Cost Procedure, has been instituted to assist Participants in making decisions regarding which units should be run each day to further maximize economy of operations within reliability limits. Additionally, MAPP is exploring the feasibility of MAPP area-wide unit commitment and economic dispatch.

The Mid-continent Area Power Pool (MAPP) membership includes 44 systems. There are 27 Participants consisting of 11 investor-owned systems, 8 G&T cooperatives, 3 public power districts, 4 municipal systems, and 1 Federal agency. The Associate Participants consist of 2 Canadian Crown Corporations, 14 municipals, and 1 investor-owned system. The MAPP Region covers all of the states of Iowa, Minnesota, Nebraska, and North Dakota; portions of the states of Illinois, Michigan, Montana, South Dakota, and Wisconsin; and the provinces of Manitoba and Saskatchewan. Total population in the Region is about 16 million.

NPCC

Northeast Power Coordinating Council

Since no new generating units beyond present commitments are now being planned, reliability in New England and New York over the next ten years will depend largely on bringing units now complete or nearing completion into service, and on the success of the utilities' cogeneration, load management, conservation and life extension programs. Reliability in Ontario, Quebec, New Brunswick and Nova Scotia will be adequate.



Actual			Forecast		
	Summer	1985	1986	1995	Growth Rate
	Winter	1985/86	1986/87	1995/96	(%/year)
NPCC — United States					
Summer Peak — MW		40,010	40,820	47,701	1.7
Winter Peak — MW		38,233	39,003	45,419	1.7
Annual Energy — GWh		220,782	226,628	268,044	1.9
Installed Capability (summer) — MW		51,319	52,396	56,098	0.8
NPCC — Canada					
Summer Peak — MW		31,549	32,804	42,868	3.0
Winter Peak — MW		46,864	46,699	60,474	2.9
Annual Energy — GWh		246,840	248,943	331,311	3.2
Installed Capability (winter) — MW		56,640	59,327	68,039	1.5
NPCC — Total					
Summer Peak — MW		71,559	73,624	90,569	2.3
Winter Peak — MW		85,097	85,702	105,893	2.4
Annual Energy — GWh		467,622	475,571	599,355	2.6
Installed Capability (winter) — MW		109,624	113,913	125,556	1.1

Demand Forecasts

Consumption of electric energy increased from 1984 to 1985 by about 2% among NPCC systems in the United States and by about 5% among NPCC systems in Canada. Energy and peak demand generally exceeded forecasts.

The 1985 and 1986 long-term forecasts are compared in the following table:

NPCC — Forecast Average Annual Increase Over the Next 10 Years (%/yr)		
	NPCC/U.S.	NPCC/Canada
Peak Demand — 1986 Forecast	1.7	2.9
Peak Demand — 1985 Forecast	1.6	3.0
Annual Energy — 1986 Forecast	1.9	3.2
Annual Energy — 1985 Forecast	1.7	3.1

This is equivalent to an average annual growth in peak demand of over 2,000 MW for all of NPCC. For certain systems, these forecasts include the effects of load management and conservation programs, as described in the next section.

Resources

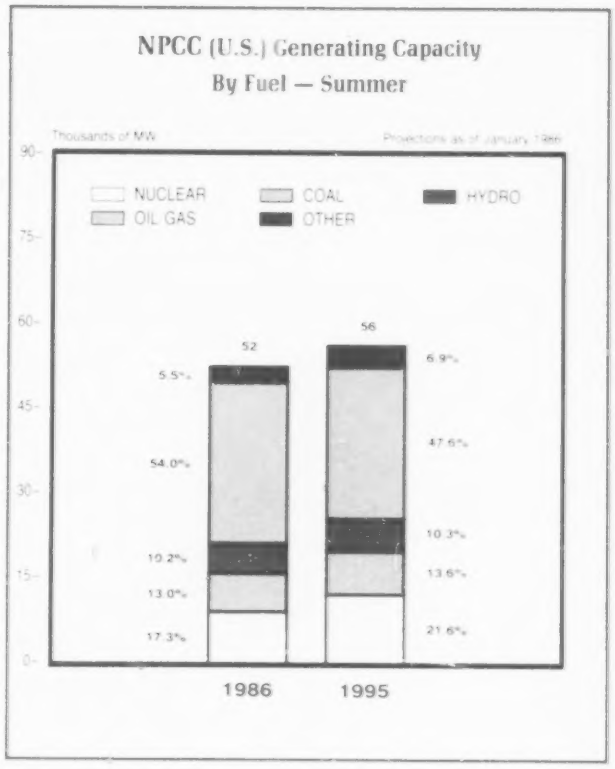
With the completion of the initial phase of the LaGrande Complex, Hydro-Quebec will have sufficient generation to meet its capacity requirements up to the year 1990 and its energy requirements to the late 1990's. In addition, in 1985, construction of additional capacity at Manic 5 (980 MW) and LaGrande 2 A (1,900 MW) was committed. Commissioning of these new units will begin in 1989 and 1992 respectively, and will fulfill capacity needs up to 1994. Other capacity projects are being studied in Hydro-Quebec for the period 1995-2001 and include gas turbines, pumped storage plants, additional capacity at existing hydro stations and also load management. The next baseload addition, LaGrande 1, will have a capacity of 1,368 MW and will not be required before the end of the 1990's.

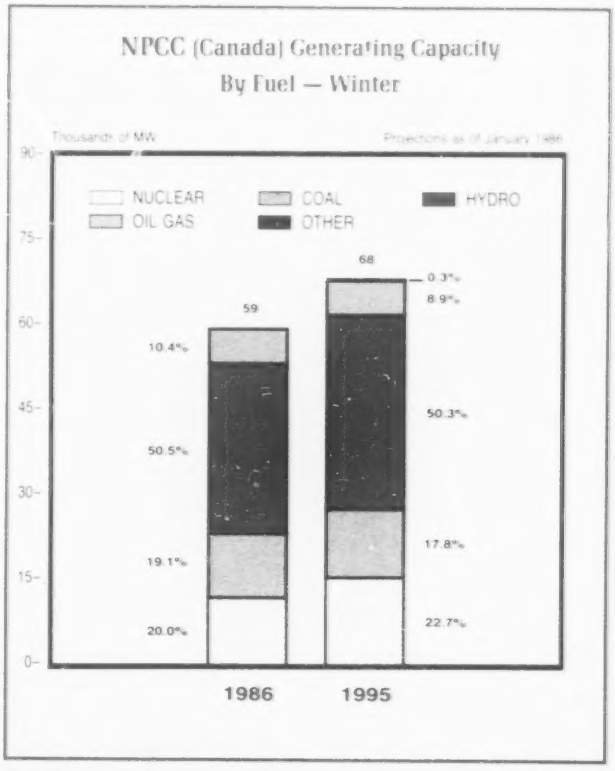
In Nova Scotia Power, approximately 1,200 MW of new capacity will be needed in the 1990's. Approval for the first 300 MW to come on line in 1991 is expected in the very near future.

New Brunswick Power has sufficient generation installed to meet its requirements to the winter of 1992 3. Additional fossil-fired capacity is now being investigated. New Brunswick Power will be concentrating its efforts in areas such as industrial load management and interconnection opportunities such as capacity purchases which might be used to delay the need for new generation additions or to make capacity-plus-energy export sales more attractive. Smaller scale opportunities exist in New Brunswick such as hydroelectric developments, and wood and waste projects, particularly as cogenerators. Provisions are being made in the Chatham circulating fluidized bed demonstration unit for future installation of equipment which could burn wood waste products.

Committed generating capacity additions on the Ontario Hydro system from January 1986 to the end of 1994 consist of 7 nuclear units (1-Pickering B, 2-Bruce B and 4-Darlington) totaling 5,700 MW. The projected total dependable capacity on the system will increase to about 34,000 MW by 1994. This program is adequate to meet system requirements until the mid-1990's. Ontario Hydro is currently examining a wide range of demand supply options to meet the additional capacity requirements of the late 1990's and beyond. Some of the options being pursued to meet requirements through the end of the century are about 1,100 MW of hydro generation, 330 MW of independently-owned capacity (primarily cogeneration), and 1,000 MW of load management.

In the New England Power Pool, a preliminary generation expansion plan through the year 2000 places additional reliance on customer generation (about 2,000 MW) and requires new uncommitted generating units (about 3,000 MW) as well as load management at nearly the same levels as





reported in 1985 (about 1,200 MW). Seabrook #1 (1,150 MW nuclear) is expected to be placed in commercial operation in the spring of 1987.

The first new utility generating capacity added in the New England Power Pool after Seabrook #1 is likely to be combustion turbine type units. Later in the period, expansion alternatives include the possibility of phased conversion of the combustion turbine units to combined cycle units for increased energy output. Coal-fired steam units will probably not be installed before the year 2000. Capacity purchases from Hydro-Quebec, New Brunswick and Nova Scotia for the period 1995-2000 are possible.

There are 4 major capacity additions in the New York Power Pool plan: 2 nuclear units, 1 hydro project and 1 pumped storage hydro installation. The first is the 809 MW Shoreham nuclear unit, built and owned by Long Island Lighting Company (LILCO). It has been 100% complete for more than a year and finished low power tests (5%) in October 1985. Full operation of the plant is awaiting an NRC operating license. In February, the Federal Emergency Management Agency conducted a test of LILCO's emergency evacuation plan as the final step required for the operating license. However, operation of Shoreham has been vigorously opposed by the state and local governments.

The investor-owned members of the New York Power Pool recently conducted a reliability study, covering the 1986-1991 period, to determine the probability of customer appeals and voltage reductions that would occur on Long Island, with and without the 809 MW Shoreham unit in service. The study showed that the reliability of the LILCO system without Shoreham is marginal at present with respect to meeting the NYPP generation reliability criterion and will deteriorate as the load grows because of inadequate transmission capacity from the mainland. By 1991, the frequency of voltage reductions and customer appeals on Long Island will be high, well in excess of acceptable levels.

The 1,080 MW Nine Mile Point 2 nuclear unit, built by Niagara Mohawk Power Corporation and jointly owned with 4 other NYPP members, is virtually complete and expected to be in commercial operation by January 1987. The Niagara Expansion project, a 300 MW hydro peaking project, is expected to be completed by May 1994. The Prattsville 1,000 MW pumped storage project has continually been delayed by environmental issues, and its service date is now estimated as April 1996.

In addition to these 4 major facilities, the New York Power Pool members will build and own various types of small power facilities, including small hydro and refuse, totaling 274 MW by 2002. Conservation and load management represent an important aspect of New York's long range plan. Member systems project that conservation and load management will reduce demand by about 1,900 MW between the present and the year 2002. Without it, expected demand in New York would grow at a 1.8% rate, rather than the 1.4% rate now forecast. Finally, independent power producers are expected to supply about 1,200 MW of additional capacity by 2002.

Many of the NPCC member systems are actively studying the technical and economic feasibility of refurbishing their older units. To the extent that life extension for many older units can be realized, it will help defer the need for new generating capacity. For example, Hydro-Quebec is engaged in a generating station improvement program which will add about 350 MW to the system capacity over the next 10 years.

Over 3,300 MW of cogeneration and other independently owned capacity is expected on the New York and New England systems by 1995. This amounts to over 5% of total resources, or about 7% of the combined forecast peak load of the 2 pools. Considered another way, the capacity expected from cogeneration and other independent power producers in New York and New England in 1995 is equivalent to more than 4 years of load growth at presently forecast rates.

There is some concern in both pools, however, about the dependability of this capacity. Reliability could be adversely affected by the fact that most of it will not be dispatched by either the pool or member utility system operators. Further, low or unstable oil prices may result in cancellation of some planned installations by the independent producers themselves.

Only a small amount of cogeneration is assumed for the next ten years by NPCC's Canadian members. As a result, the effect on reliability is small.

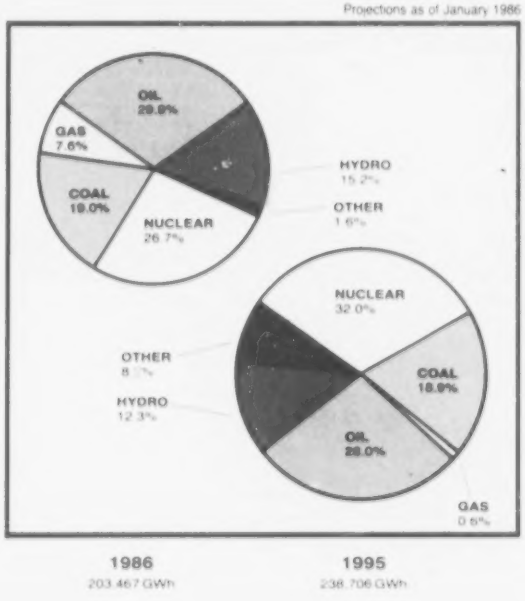
Transmission

An extensive study program is continuing under the direction of a NYPP NEPOOL HQ NBP Steering Committee to determine the system configuration and the operating procedures necessary to make the proposed HQ NEPOOL 2,000 MW interconnection function in a reliable manner when placed in service in 1990. These studies will be reviewed and critiqued by the other systems within the MAAC-ECAR-NPCC (MEN) area, and, to this end, a MEN 1990 study is already in progress.

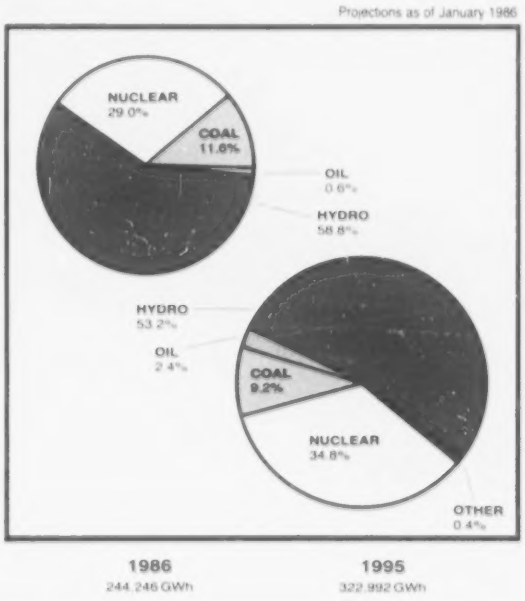
A study of the possible addition of a second 345 kV tie line between New England and New Brunswick is continuing. Such a line would facilitate New England purchases of entitlements in generating units located in New Brunswick as well as permit additional surplus energy from Hydro-Quebec and Nova Scotia to be delivered to New England.

Additional transmission lines are required in NYPP to increase the capability to transfer economy energy and respond to emergencies. One such project is the 200-mile 345 kV Marcy-South reinforcement between central and southeastern New York. This is a predominantly double circuit reinforcement,

NPCC (U.S.) Electric Energy Production By Fuel



NPCC (Canada) Electric Energy Production By Fuel



portions of which are scheduled to be completed in 1987 and 1988. When completed, Marcy-South will reduce NYPP's dependence on foreign oil by allowing the displacement of oil-fired generation with more economical energy from internal NYPP and Canadian sources. The project will also improve reliability, particularly in southeastern New York.

A planned reinforcement of the 345 kV cable system between the New York mainland and Long Island, scheduled for 1991, will both increase economy transfer capability and improve reliability on Long Island.

Because of regulatory uncertainties, the Seabrook-Tewksbury 345 kV line between southeastern New Hampshire and northeastern Massachusetts will not be completed in time to meet the Seabrook unit's in-service date. The effect of delay will be to confine a significant amount of generation in northern New England.

A new environmental assessment in Ontario covering a transmission plan for completing the incorporation of the Bruce nuclear complex on Lake Huron, as well as providing a reliable supply to forecast load growth in the southwestern portion of the province and maintaining transfer capability to the international border with Michigan, was completed and submitted to the government in August 1985. This new assessment was required because the approval of an earlier plan stage environmental assessment had been quashed by the Supreme Court of Ontario on a technicality in June 1984. The new assessment also covers routes for the new transmission lines and a new transformer station west of London, Ontario. Provincial government hearings on this environmental assessment commenced in mid-November 1985, and are not expected to be completed before October 1986. At this time, it appears unlikely that additional transmission facilities out of Bruce will be in place before the end of 1989.

The provincial government has recently given its approval to Ontario Hydro to construct two 500 kV lines from the Lennox Generating Station on Lake Ontario, and one 500 kV line from Cornwall, to the city of Ottawa to supply load growth in the Ottawa area. Although the first of these lines was needed more than 2 years ago to meet reliability criteria, because of approval delays it will not be ready for service until just before the 1989-90 winter season.

Operations

Operating responsibility within NPCC resides with the individual systems in Canada, and with the two power pools in the U.S. Each Canadian system operates its own control center. Within the U.S. power pools, a hierarchical system of control is used. In NEPOOL, control proceeds from the New England Power Exchange (NEPEX) dispatch center to satellite centers, and then in turn to the individual member systems; in NYPP, control is from the NYPP center directly to the utilities.

Both voice and telecommunications systems are maintained among the NPCC pool and Canadian system control centers,

and also with neighboring systems. NYPP, NEPOOL and Ontario Hydro, along with PJM, are also linked by a computer-to-computer communication system. Such multi-system monitoring on a real time basis greatly assists system operators in monitoring and controlling their systems, especially with regard to power transfers among numbers of parties and the resulting parallel path flow problems.

The various NPCC systems and the PJM power pool are continuing a test program for Shared Activation of Reserve. Using this procedure, any of the participating operating areas can recover more quickly from the loss of a unit because all areas participate in the activation of ten minutes reserve.

NPCC maintains a number of operating instructions, procedures, guides and criteria covering virtually all areas of operations. Member system conformance with these is monitored on a regular basis. In addition, training sessions for operating personnel are conducted twice a year.

The Northeast Power Coordinating Council (NPCC) represents 22 investor and publicly-owned utility systems serving about 43 million people in the Northeastern United States and Eastern Canada. In the United States, NPCC members participate in either the New England Power Pool (NEPOOL) or the New York Power Pool (NYPP). In Canada, the 4 members — Ontario Hydro, Hydro-Quebec, New Brunswick Power and Nova Scotia Power — are province-wide systems and make up 3 of NPCC's 5 Areas. Together, the NPCC members supply about 98% of all the electricity in the NPCC Region.

SERC

Southeastern Electric Reliability Council

Generating capacity margins in SERC are judged to be adequate during the review period. These margins are expected to decrease over the 10-year period as reserves approach planned levels. Also, emergency transfer capabilities between subregions, and between SERC and other regions, are expected to be adequate. There are concerns about the possible effects of load forecast uncertainty, load management and cogeneration as committed resources, and the lack of commitment for new generating capacity.

Actual			Forecast		
	Summer	1985	1986	1995	Growth Rate (%/year)
	Winter	1985/86	1986/87	1995/96	
Summer Peak — MW		98,572	100,818	124,619	2.4
Winter Peak — MW		102,894	99,450	122,442	2.3
Annual Energy — GWh		522,648	526,291	657,999	2.5
Installed Capability (win./sum.) — MW		134,754 (w)	133,167 (s)	151,113 (s)	1.4

Demand and Energy

The SERC Region covers a diverse geographic and socio-economic area of 345,650 square miles in the Southeastern United States. The VACAR and Southern Subregions have historically been summer peaking, and the TVA and Florida Subregions have been winter peaking. By the end of the 10-year period, the TVA and VACAR Subregions are projecting practically no difference between summer and winter peak load demands, while Southern and Florida remain solidly summer peaking and winter peaking, respectively.

SERC Summer 1985			
	Forecast Peak Demand (MW)	Actual Peak Demand (MW)	Increase Over Forecast (%)
Florida	20,706	21,834	5.4
Southern	23,063	25,510	10.6
TVA	19,743	18,532	(6.1)
VACAR	33,805	32,696	(3.3)
Total	97,317	98,572	1.3

SERC Projected Annual Growth Rate (%/Yr) 1986-1995			
Subregion	Summer Peak Demand	Winter Peak Demand	Annual Energy
Florida	2.5	2.5	2.8
Southern	2.4	2.1	2.3
TVA	2.5	2.6	2.5
VACAR	2.1	2.2	2.5
Total	2.4	2.3	2.5

Forecasts have changed only slightly from those of last year on a regional basis. The SERC forecast growth rates of summer peak demand reduced from 2.5% to 2.4%, while forecasts of winter peak demand and annual energy changed from 2.2% to 2.3% and from 2.6% to 2.5%, respectively.

Generation Capacity and Adequacy

Capacity additions within the SERC Region for the 1986-1995 period include 5,272 MW in 10 coal-fired units, 7,898 MW in 7 nuclear units, 1,300 MW in 8 pumped storage units, 1,565 MW in 7 combined cycle units, 355 MW of combustion turbine capacity, and 76 MW of conventional hydro capacity. This results in a total capacity addition of 17,946 MW including upratings and units returned to service from extended shutdown. During the past year, several changes have been made from previous reports of the planned capacity additions for the Region. Three coal units (1,800 MW), 1 nuclear unit (1,212 MW), and 3 pumped storage units (848 MW) have been deferred beyond the reporting period. These deferrals are attributed to such factors as lower load forecasts, changes in regulatory requirements, uncertainty regarding future regulatory treatment, increased conservation and load management, additions of customer-owned generation, and increasing construction costs.

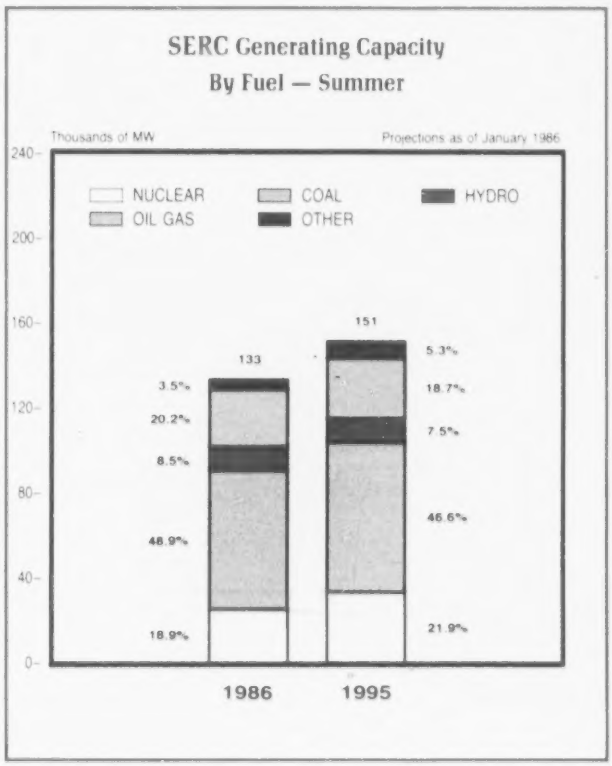
By 1989, Florida expects to have 1,515 MW of new coal capacity in service. For the next decade, almost half of the Peninsular energy needs will be provided by coal generation and coal-by-wire imports. Most of the oil units currently on extended cold standby (990 MW) are expected to be returned to service by 1995. Florida is projecting the addition of 1,020 MW of oil- and gas-fired combined cycle capacity by 1995. The projected use of oil is expected to increase from 8% of total generation in 1986 to 15% in 1995.

In the Southern Subregion, 2 nuclear units (2,300 MW) are scheduled to be added during the review period. Coal-fired baseload units and peaking facilities (combustion turbines or pumped storage hydro) will constitute the remainder of the generation expansion. The only significant generation change from last year's schedule is the delay of the Rocky Mountain pumped storage facility from 1991 to 1999 (848 MW).

In the TVA Subregion, the Watts Bar Units 1 and 2 (nuclear) were scheduled for startup in 1985 and 1988, respectively. These units have been delayed due to safety concerns, and new schedules have not been published. The schedule for the Bellefonte Nuclear Plant (units 1 and 2) has been delayed from 1989 and 1991 to 1994 and 1996, respectively. TVA's installed nuclear capability is expected to increase from 18% in 1986 to 30% by 1995.

During the period, utilities of VACAR expect to add 2,045 MW of nuclear (2 units), 1,150 MW of pumped storage hydro (6 units), 1,671 MW of fossil (4 units) and 517 MW of combined cycle (3 units). VACAR utilities continue to reduce dependence on oil by conversions from oil to coal operation. Approximately 202 MW is scheduled for conversion by mid-1987. With this conversion, more than 3,600 MW will have been converted from dependence on oil or distillates.

The installed generating capacity margins for the subregions of SERC are projected to decrease in this review period, but are considered to be adequate. If a sustained demand growth higher than forecast occurs, resources could be marginal in some subregions in the late 1980's or early 1990's. Individual systems may then be faced with less than desirable capacity margins before any required new baseload generation could be placed in service or mothballed capacity returned to service.



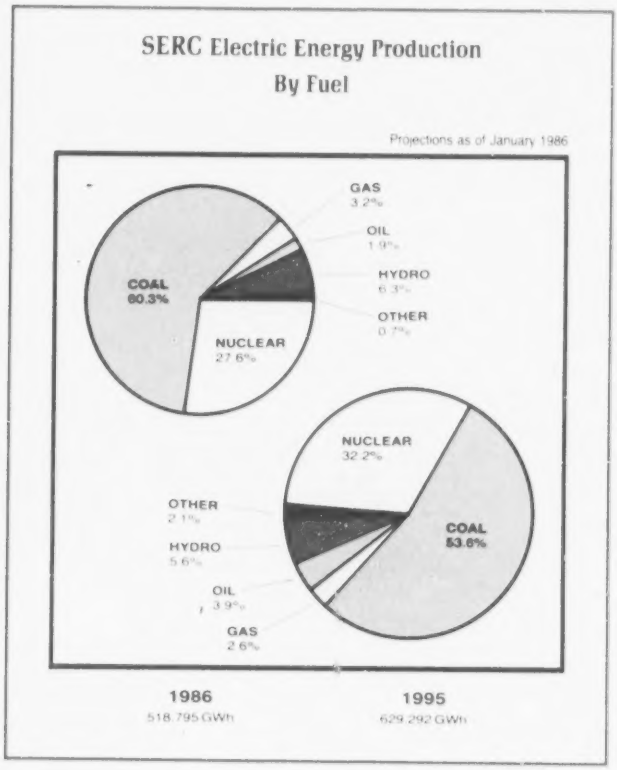
Transmission

The existing transmission systems in SERC include over 19,000 miles of 230 kV and almost 7,000 miles of 500 kV transmission lines. During the review period, 1,889 miles of 230 kV and 889 miles of 500 kV are expected to be added in the Region. These additions include 2 major 500 kV interconnections between the TVA Subregion of SERC and the SPP Region to be completed by the summer of 1988.

SERC systems have coordinated their transmission planning to assure the continued development of a reliable transmission network. Analysis of current studies indicates that existing facilities, along with those planned to meet the reliability needs of the SERC subregions, will also provide adequate emergency transfer capability between SERC and other surrounding regions and between subregions of SERC. All systems of SERC expect to meet SERC reliability criteria during the review period.

Peninsular Florida has historically been a major user of oil as a boiler fuel in producing electrical energy. During 1985, a cost effective oil backout study was conducted to evaluate the cost

effectiveness of constructing additional transmission facilities in order to raise the transfer capability from Southern to Florida above the 3,200 MW level. This study was produced through the cooperative efforts of representatives from the Florida Electric Power Coordinating Group, Southern, TVA, and the Florida Public Service Commission staff. In order to evaluate cost effectiveness, the cost of new transmission facilities and the potential fuel savings were identified. The study indicated that no additional transmission for this purpose was economically justified.



Operations

The electric system of the Southern Subregion made 27,696 GWh of off-system sales in 1985, a 32% increase over 1984. Since a high percentage of these sales was to oil- and gas-burning subregions, it is estimated that the sales may have resulted in displacing as much as 44.3 million barrels of oil. The last link of the Florida east coast 500 kV transmission system was completed in June 1985 and the reliable transfer capability from Southern to Florida increased from 2,900 to 3,200 MW. Completion of this 500 kV system also strengthened Florida's internal transmission system, alleviating several constraints. As a result, there were no electrical separations from the Southern electric system in 1985. Special protection systems have been applied within Florida to force controlled separations or load shedding for certain multiple contingencies. A procedure for monitoring Florida's responsiveness to operating reserve requirements was implemented and provides for review of situations where operating guides are violated.

Because of increasing regulatory and safety concerns, TVA decided to temporarily cease operation at the Brown's Ferry nuclear plant beginning in March 1985 and the Sequoyah nuclear plant in August 1985. The effects of the reduced nuclear availability were an increase in generation from TVA's coal-fired system and additional off-system purchases. The additional purchases were made without jeopardizing the reliability of service within the TVA system and with no detrimental effect on the reliability of the interconnected network. TVA is strongly interconnected with neighboring systems through 30 interconnections, 7 of which are at 500 kV, 1 at 345 kV and 1 at 230 kV. These interconnections allow the higher level of purchase while maintaining system reliability during the period of reduced nuclear generation.

Several systems within SERC are participating with other systems in ECAR, MAAC and NPCC to develop a communication network for the exchange of operating data. This developmental project will define a system configuration and protocol that will permit direct data exchange among energy system management computers in control centers of the project participants. This data exchange via computer-to-computer communication links will further enhance the reliable operation of the participating systems.

Major Regional Issues

Effect on Transmission by Economy Transfers — Large blocks of simultaneous economy transfers can significantly alter the flow pattern of the bulk power transmission network and limit its emergency transfer capability. Issues related to transmission access can contribute to this potential problem.

Transmission systems were designed for reliability purposes and to transmit energy from generating stations to load areas. These systems also provide support to neighboring utilities in times of emergency. For economic reasons, however, utilities have increased loading on interconnections with purchases and sales, leaving less margin for reliability. Even though economy transfers in 1986 are greatly reduced from 1985 levels due to reduced prices for oil and gas fuels, a future change in fuel prices can again return utilities to heavy transmission flows in order to reduce the overall cost to utility customers.

Load Forecast Uncertainty — Electrical demand is influenced by a great number of factors, many of which are beyond the control of utilities. Upward trends in growth rates could advance the need for new generation by as much as four to five years. Downward trends in load growth are also of concern if significant expenditures have been committed for generating resources. Bandwidth forecasts are being used by some systems to identify the uncertainties inherent in load forecasts.

Cogeneration and Small Power Production — Cogeneration and small power producers are being considered as a source of capacity in utilities' generation expansion plans. However,

since these producers are not in business solely to provide energy, many utilities are concerned that this resource will not be available to meet customer demand. Other concerns are the inability of utilities to determine the maintenance scheduling and the dispatching of cogeneration capacity, and the long-term uncertainty of whether a cogenerator or small power producer will choose to stay in the power production business.

Load Management — Load management was an idea born in an era of energy crisis when consumers first became conservation conscious. Whether the consumers of the 1990's will still want load management is an uncertainty which must be considered by utility planners.

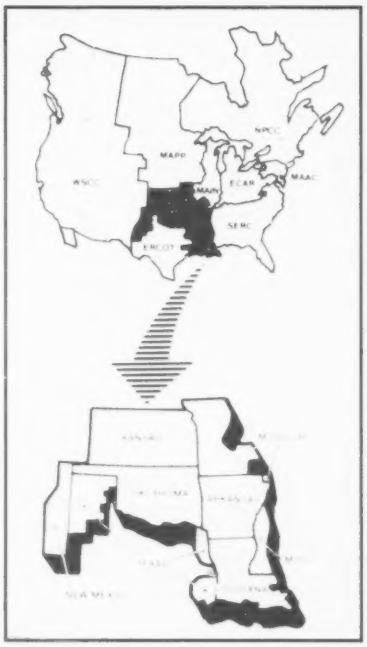
In the meantime, plans are being made which consider load management as a committed resource. Utilities are now gathering data to predict the actual effect of load management on programs on electrical demand under varying system conditions. The data being gathered and the reduced fuel price forecast have led utilities to question the cost effectiveness of load management. Some utilities now feel that more time is needed to determine the true cost effectiveness of this alternative.

Lack of Commitment to New Generating Capacity — Load forecast uncertainty, cogeneration and load management uncertainty, financial constraints, unknown legislative action, and regulatory uncertainty are contributing factors to this dilemma. Faced with these uncertainties, there is an increased reluctance by utility management to make firm commitments to construct new generating resources. This is particularly true of commitments to long lead time, high capital cost options such as coal or nuclear. There is an increasing interest in shorter lead time, lower capital cost options such as combustion turbines or combined cycle units.

The Southeastern Electric Reliability Council (SERC) includes 28 utility member systems located in 9 states in the Southeastern United States. SERC is divided into 4 subregions which are identified by the Florida peninsula (Florida), the geographical bounds of the Southern electric system (Southern), the geographical bounds of the Tennessee Valley Authority (TVA), and the Virginia-Carolinas area (VACAR).

SPP

Southwest Power Pool



Three nuclear generating units added in 1985 and one to be in service during 1986 will help ensure sufficient generating capacity for several years. In the 1986 to 1995 decade, the current plans for generator additions and EHV transmission are expected to provide a reliable bulk power system. Some uncertainty exists about the ability to respond to sudden changes in the price and availability of gas and oil or sharp upsurges in load growth.

	Actual		Forecast		
	Summer	1985	1986	1995	Growth Rate
	Winter	1985/86	1986/87	1995/96	(%/year)
Summer Peak — MW		45,026	47,298	57,928	2.3
Winter Peak — MW		34,618	34,829	43,863	2.6
Annual Energy — GWh		229,677	223,357	271,718	2.2
Installed Capability (summer) — MW		62,225	65,201	69,429	0.7

Demand and Energy Forecast

Forecasts have been reduced since last year. For the 1986-1995 period, the demand growth rate has changed from 2.5% to 2.3% while energy growth has declined from 2.6% to 2.2%. These changes are significant and represent the impact of the slumping petroleum industry in Texas, Oklahoma and Louisiana. With the abrupt drop in oil prices during early 1986, it is doubtful that the full effect was captured in all of the individual system forecasts. It is interesting that the summer peaking SPP reports growth rates of 2.3% for summer demand, 2.6% for winter demand, and 2.2% for energy. Efforts to control summer peaks and encourage winter loads appear to be successful. However, the low energy growth can be a serious problem because of the direct effect on revenue. It reflects a loss of high load factor industrial loads, especially in the petrochemical industry in the gulf coast area. The loss of load is partly due to the installation of self generation.

Generation Additions

Generation additions in SPP are notable for the 3 nuclear generating units placed in service during 1985. Grand Gulf 1, Waterford 3 and Wolf Creek 1 represented 3,065 MW of nuclear additions. In 1986, Riverbend 1 will add 940 MW.

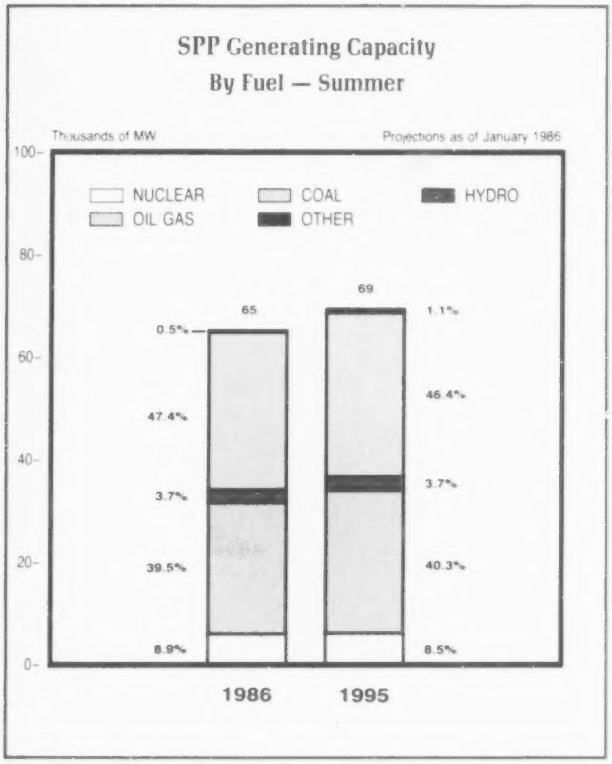
During the 1986 to 1995 period, a total of 7,216 MW new or uprated generation, and 1,462 MW reactivated generation is planned. Of this, 48% is coal-fueled and 38% will be oil or natural gas-fueled. The year 1986 will see 701 MW of new coal-fired generation in addition to the aforementioned nuclear. After retirements and other reductions, the net capacity increase will be 6,376 MW for the decade.

However, after 1986, in keeping with national trends, no new nuclear units are planned during the next 10 years and no coal-fired units are planned until 1992. Of the 7,200 MW of planned generation additions, approximately 3,200 MW have not been utility authorized. This indicates a strong reluctance on the part of the utilities to make commitments to the large financial investments required for baseload coal units. Many of the generators scheduled for the mid-1990's may be deferred until there is more certainty they definitely will be needed and that they will be approved for inclusion in rate base.

Because there was sufficient capability in service, about 1,900 MW of generation was placed on inactive status during 1985. This will reduce expenses while providing a ready reservoir of capacity which can be returned to service as needed.

Adequacy of Power Supply

The adequacy of SPP for the period 1986-1995 is satisfactory, based on present demand and energy forecastss, the schedule of new generating unit additions, and the adition of new



transmission lines. However, there are two general areas of concern that could adversely affect SPP's future reliability. These are:

- Future availability of gas and oil fuels will continue to be a concern. The current low prices have virtually stopped all exploration and drilling. Increased consumption will deplete reserves and make future availability less certain.
- Ability to react to a major upsurge in load growth is also a concern. Because of the long lead time required to construct major generating units, a significant increase in demands above that now forecast could lead to an adequacy problem in the 1990's.

Based on the current peak demand forecast and generating capacity addition schedule, the projected capacity margin of SPP for the 1986-1995 summer periods will decline from 27.2% to 16.6%. Present projections show that SPP will require 806 billion cubic feet of gas and 2.4 million barrels of oil to generate its energy requirements in 1995. This represents 31% of SPP's total energy generation in 1995.

Transmission

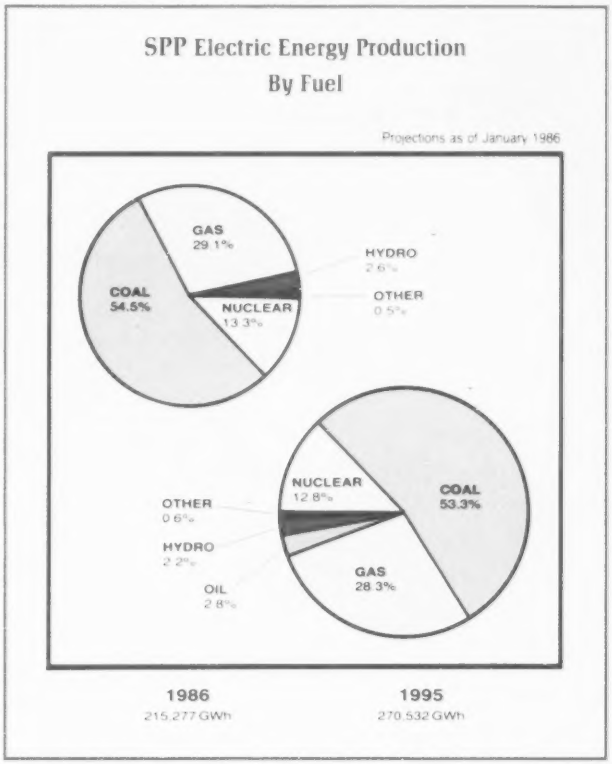
Several EHV lines were placed in service in 1985, including three 345 kV lines and two 500 kV lines. The SPP will build 550 miles of 345 kV and 362 miles of 500 kV in the next decade. Two 500 kV connections are scheduled between SPP and SERC (TVA) for 1988. A 500 MW dc facility, which will interconnect ERCOT and SPP, is planned for 1989.

Operations

A number of systems have installed control center computers recently. Others will replace older equipment within the next few years. These state-of-the-art computer systems will improve reliability by providing the system operators more complete and timely information. Some will have state estimation capability which helps evaluate system security for changing conditions. Operator training is also receiving more emphasis.

The Southeastern Subregion has experienced large north-to-south transfers in the past. With nuclear generation added in the south, these transfers will become bidirectional. For the next few years, there will be some problems in reducing nuclear and coal-fired generation to match minimum load levels. The problems will be self-correcting as demand grows.

There is some apprehension about the possibility of transmission access by non-utilities. Any use of the transmission network that is not controlled by the system operators can jeopardize reliability and system operation.



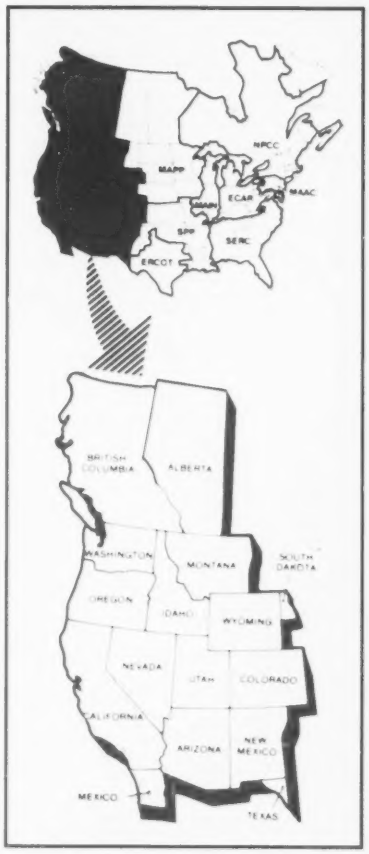
The Southwest Power Pool (SPP) includes 38 power suppliers serving customers in the states of Kansas, Oklahoma, Missouri, Arkansas, Mississippi, Louisiana, Texas and New Mexico. The membership is composed of 11 municipals, 2 state agencies, 7 cooperatives, 17 investor-owned utilities and 1 Federal agency.

WSCC

Western Systems Coordinating Council

The actual load growth rate in the WSCC Region has dropped and remains below earlier projections. As a consequence, generating reserve levels have increased and surplus energy transactions have displaced a larger share of higher-cost oil and gas-fired generation. Despite the current decline in oil and gas prices, economy energy transfers will continue. Transmission paths to California will remain heavily loaded over extended periods as this optimization process continues.

The Region will continue to rely on Remedial Action Schemes, also known as Special Protection Systems, to satisfy its reliability criteria. Member systems will continue upgrading the reliability of these schemes.



Actual			Forecast		
	Summer	1985	1986	1995	Growth Rate (%/year)
	Winter	1985/86	1986/87	1995/96	
WSCC — United States					
Summer Peak — MW		83,119	84,862	104,108	2.3
Winter Peak — MW		77,997	81,592	97,473	2.0
Annual Energy — GWh		478,790	487,253	598,724	2.3
Installed Capability (summer) — MW		119,417	120,964	135,171	1.2
WSCC — Canada					
Summer Peak — MW		9,516	10,247	13,174	2.8
Winter Peak — MW		12,299	12,663	15,994	2.6
Annual Energy — GWh		71,673	73,827	95,559	2.9
Installed Capability (winter) — MW		17,426	17,680	19,371	1.0
WSCC — Mexico					
Summer Peak — MW		619	644	1,196	7.1
Winter Peak — MW		397	416	773	7.1
Annual Energy — GWh		2,612	2,970	5,623	7.3
Installed Capability (summer) — MW		628	928	1,463	5.2
WSCC — Total					
Summer Peak — MW		93,235	95,386	118,101	2.4
Winter Peak — MW		90,693	94,436	114,240	2.1
Annual Energy — GWh		553,075	564,050	699,906	2.4
Installed Capability (summer) — MW		137,574	139,794	155,884	1.2

Peak Demand and Energy

The accompanying tables provide a comparison of this year's forecast of peak demand and energy with last year's forecast and summarize the 1985 peak demand and energy experience.

WSCC (U.S., Canada and Mexico)
Comparison of Forecasts

	This Year's Forecast (1986-1995)	Last Year's Forecast (1985-1994)
10-Year Forecasts:		
Summer Peak Demand Growth Rate (% / yr)	2.4	2.4
Annual Energy Growth Rate (% / yr)	2.4	2.5
Forecasts for Year 1994:		
Summer Peak Demand — MW	115,672	111,911
% Change	3.4	
Annual Energy — GWh (Median Hydro)	685,500	677,828
% Change	1.1	

WSCC (U.S., Canada and Mexico)
1985 Peak Demand and Energy Experience

	1985 Actual vs 1984 Actual	1985 Actual vs 1985 Forecast
Summer Peak Demand	4.6	3.1
December Peak Demand	2.2	4.5
Annual Energy	3.2	1.4

Generating Capacity and Energy Supply

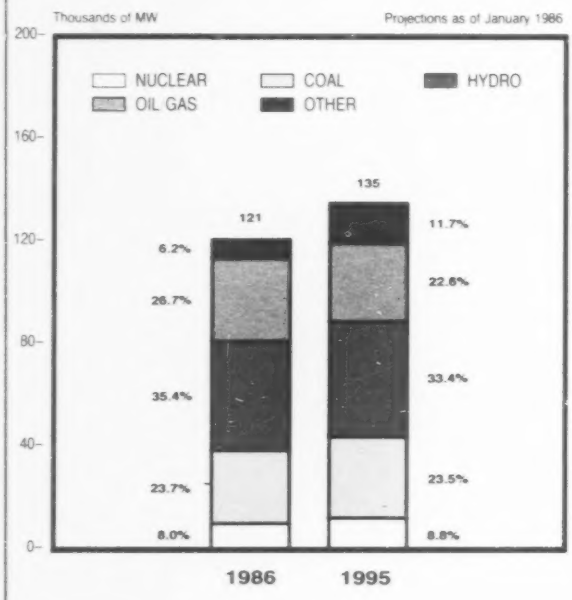
Planned generating capacity additions for the 1986-1995 period continue to reflect a reliance on coal and nuclear units.[1] Net hydro generating capacity additions (3,447 MW) planned through the end of the 10-year period represent 15% of the total planned generating capacity additions within the Region. Net coal-fired generating capacity additions (8,280 MW) and nuclear capacity additions (4,150 MW) represent 35% and 18% respectively of WSCC's total planned generating capacity additions during the next 10 years. Cogeneration additions (5,575 MW) represent 24% of WSCC's planned generating capacity additions, a 111% increase over the planned cogeneration additions (2,641 MW) reported for the 1985-1994 period.

[1]WNP1 (1,250 MW) and WNP3 (1,240 MW) are under review and are not counted as part of the NERC capacity during this review period.

There have been about 2,737 MW of deferrals and cancellations of generating units which were reported in the resource plans of one year ago. The reduction in planned generation additions is due to the adequate capacity margins which are projected over the next 10 years. Generating capacity margins projected for the summer peak range between 22% and 29% for the next 10 years. These capacity margins will enable WSCC to respond to additional load growth above that forecast in the event of an accelerated economic recovery.

Currently, 14,447 MW of the total 23,602 MW net capacity additions planned to be operational in 1995 are not yet under construction. Discounting non-utility capacity additions which typically have a 1 to 2 year construction period, the Region will have reduced ability to respond to increases in demand in the 1990's if this capacity is not built.

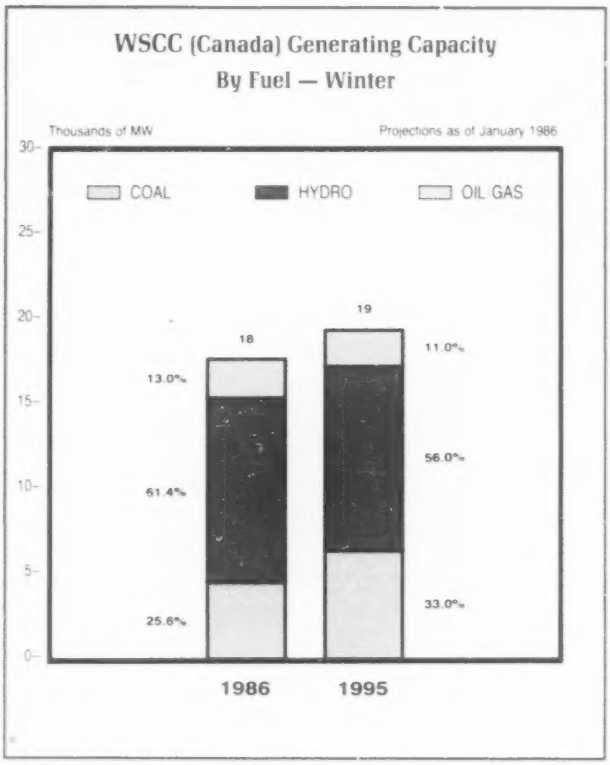
WSCC (U.S.) Generating Capacity
By Fuel — Summer

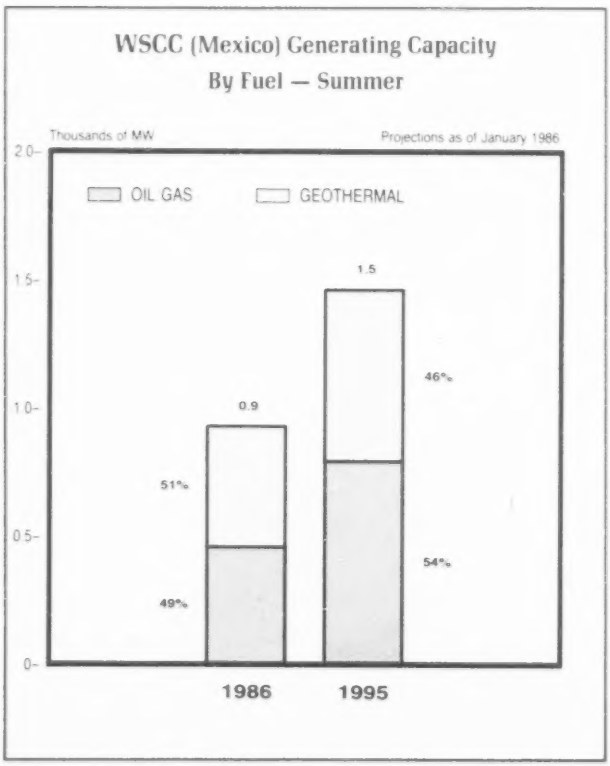


Transmission Adequacy and Operations

The WSCC interconnected transmission system is expected to be generally adequate to accommodate anticipated firm and most economy energy schedules during the 10-year period (1986-1995).

A continuing issue of major concern throughout WSCC is the effect of economy transfers on bulk power system reliability. The Region's diverse load and resource mix, combined with





localized surpluses of baseload capacity, large fuel price differentials, and a trend toward more efficient operation on a regional scale, make surplus energy transfers between areas economically beneficial.

Because of these increased economy energy transfers, the transmission system is being loaded to higher levels for sustained periods of time. Thus, the bulk transmission system is being operated to provide greater economic advantages but this mode of operation poses greater risks to system reliability because of reduced operating margin.

In light of the increased risk, WSCC is making a concerted effort to maintain an acceptable level of system reliability. Major work will be completed during 1986 to improve the reliability of the Pacific Intertie and associated remedial action schemes. Relays and associated equipment are being replaced, additional circuit breakers and redundant communication systems are being added where appropriate and studies are being conducted to evaluate the addition of an independent detection scheme to initiate controlled islanding for loss of the ac Pacific Intertie should the primary transfer trip scheme fail.

As an additional measure to provide for reliable system operation during periods of high transfers, nomograms are developed prior to each operating season which define the maximum permissible simultaneous flow levels on key transmission paths to help assure that acceptable system performance can be maintained in the event of a disturbance. Currently, the use of nomograms is required for simultaneous imports to California from the Northwest and Arizona, and for exports from Montana to the Northwest.

During the 1986-1991 time frame, several key transmission projects are likely to have a significant effect on the operation of the WSCC interconnected system. These projects include:

- Upgrading the transfer capability of the Northwest to California 500 kV ac Pacific Intertie from 2,800 MW to 3,200 MW — 1986.
- Completion of the 1,520 MW Intermountain Power Project Generating Plant in Utah and the associated ± 500 kV dc line to California — 1986-1987.
- Expansion Project of dc terminal to upgrade the ± 500 kV Celilo-Sylmar dc line from 2,000 MW to 3,100 MW — 1989.
- Completion of the third Northwest to California 500 kV ac Pacific Intertie — 1991.
- Increasing the Arizona-California transfer capability to 5,500 MW — 1987.
- The addition of phase shifting transformers in Southwestern Colorado to control loop flow — 1988.

The Council has placed a high priority on studying the effects of these projects on the reliability of the WSCC interconnected system and evaluating alternative remedial action schemes which will confine the effects of disturbances involving these projects to the project participants, consequently minimizing the effects on neighboring systems.

Cogeneration and Small Power Production Renewable and Alternative Energy Resources

Of the 4 WSCC Areas, the California-Southern Nevada Power Area is projecting the most growth in cogeneration and small power production and renewable and alternative energy resources. At present, there are over 2,000 MW of cogeneration and small power resources on line, including over 12,000 windmills driving induction generators. Although the current projection indicates the addition of 5,365 MW of cogeneration facilities during the next 10 years, contracts have been signed with developers for over 15,000 MW of cogeneration and small power facilities. If all the capacity for which contracts have been signed is placed in service during the next 10 years, the Area will have a serious over-capacity problem.

Increased cogeneration and small power production facilities have been stimulated by the California regulatory commissions' interpretations of the Public Utilities Regulatory Policies Act (PURPA). Because the potential oversupply of cogeneration and small power production facilities, the California Public Utility Commission has suspended the standard offers which the California utilities were required to sign to buy power from developers.

Northwest Power Pool Area

The Northwest Power Pool Area is composed of the states of Washington, Oregon, Idaho, Utah, portions of Montana, Wyoming, Nevada and California; and the Canadian provinces of British Columbia and Alberta.

Projections of peak demand and energy requirements for the 1986-1995 period are presented in the accompanying tables. Winter generating capacity margins for this winter peaking area range between 16% and 25% for the next 10 years.

Northwest Power Pool (U.S.)
Comparison of Forecasts

	This Year's Forecast (1986-1995)	Last Year's Forecast (1985-1994)
10-Year Forecasts:		
Summer Peak Demand Growth Rate (% yr)	1.8	1.7
Annual Energy Growth Rate (% yr)	2.0	1.9
Forecasts for Year 1994:		
Summer Peak Demand MW	30,145	29,245
% Change	3.1	
Annual Energy GWh	216,753	219,345
% Change	-1.2	

Northwest Power Pool (Canada)
Comparison of Forecasts

	This Year's Forecast (1986-1995)	Last Year's Forecast (1985-1994)
10-Year Forecasts:		
Summer Peak Demand Growth Rate (% yr)	2.8	2.8
Annual Energy Growth Rate (% yr)	2.9	3.1
Forecasts for Year 1994:		
Summer Peak Demand MW	12,861	12,112
% Change	6.2	
Annual Energy GWh	93,164	90,680
% Change	2.7	

The transmission system to integrate Colstrip generation will be completed in October 1987 with completion of the Taft-Bell 500 kV line between western Montana and eastern Washington. Colstrip Unit No. 4 (700 MW) was initially operated in December 1985 and went into commercial operation in April 1986. A temporary Colstrip generator tripping scheme is in service to protect against the loss of either section of the Taft-Dworshak Dworshak-Hatwai 500 kV transmission line through northern Idaho. This scheme will remain in service at least until the Taft-Bell 500 kV line is operational.

The Cranbrook-Langdon 500 kV line between the British Columbia hydro system in southeastern British Columbia and TransAlta Utilities at Calgary, Alberta was declared commercial in January 1986. This line strengthens the interconnection between the Calgary area of Alberta and British Columbia and enables increased power transfer between the two provinces.

Project participants are proceeding with their plans to increase the capacity of the dc Pacific Intertie to 3,100 MW by 1989. Extensive system studies have been performed to determine a plan of service which will comply with WSCC reliability criteria. Study results indicate that dynamic voltage support at Malin and Table Mountain 500 kV substations and increased remedial action (generator tripping) will be required for loss of the dc line.

Plans to upgrade the ac Pacific Intertie to 4,800 MW through construction of a third 500 kV ac line in northern California are in progress. The new 500 kV line, scheduled for completion by 1991, will extend from Tesla Substation in California, north to the Malin-Meridian 500 kV line in Oregon. Addition of the third ac Intertie line will eliminate the need for the islanding scheme as remedial action for loss of the 2 existing ac Pacific Intertie lines. A number of corridor options which provide for varying degrees of separation from the existing Intertie lines are being studied.

WSCC

Rocky Mountain Power Area

The Rocky Mountain Power Area consists of Colorado, eastern Wyoming and a small part of South Dakota. The accompanying table presents this year's forecast of peak demand and energy as compared to last year's forecast. Summer generating capacity margins range between 18% and 31% for the next 10 years.

Rocky Mountain Power Area
Comparison of Forecasts

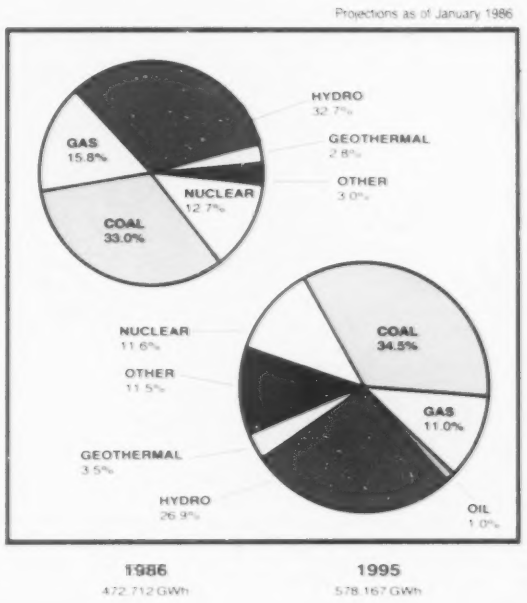
	This Year's Forecast (1986-1995)		Last Year's Forecast (1985-1994)
10-Year Forecasts:			
Summer Peak Demand Growth Rate (%/yr)	3.3		3.4
Annual Energy Growth Rate (%/yr)	2.9		3.6
Forecasts for Year 1994:			
Summer Peak Demand — MW	8,002		8,335
% Change		-4.0	
Annual Energy — GWh	46,878		49,355
% Change		-5.0	

No major generating facilities were placed in service during 1985; however, a significant amount of surplus generating capacity is available within the Area for export. This surplus capacity cannot be fully utilized due to the lack of transmission capacity to outside areas. Load forecasts indicate that over the next 5 to 10 years, the present surplus generating capacity will be absorbed by area load growth.

The Rifle-San Juan 345 kV transmission line, approximately 265 miles in length, was 40% complete by the end of 1985 and the northern section between Rifle and Montrose has been placed in service. The line, scheduled for completion during December 1986, is intended to serve western Colorado loads as well as strengthen the interconnected transmission system between Colorado and the Arizona/New Mexico area. Until the line is completed to San Juan, the existing transmission system in western Colorado will continue to be heavily stressed with firm and economy transfers. Actual transfers through the area during 1985 periodically exceeded the transfer capability limit due to circulating power flow (loop flow). Substantial amounts of loop flow are likely to continue in the future. The Western Area Power Administration is proposing to add phase shifting transformers to control loop flow in this area.

Other transmission limitations within the Rocky Mountain Power Area include the Wyoming/Colorado and Utah/Colorado transmission paths. Studies are underway to identify alternatives which will relieve these transmission limitations.

WSCC (U.S.) Electric Energy Production By Fuel



A third dc tie between WSCC and MAPP, located in southwestern Nebraska, is scheduled for completion in 1987 and will increase the transfer capability between the two regions by 200 MW.

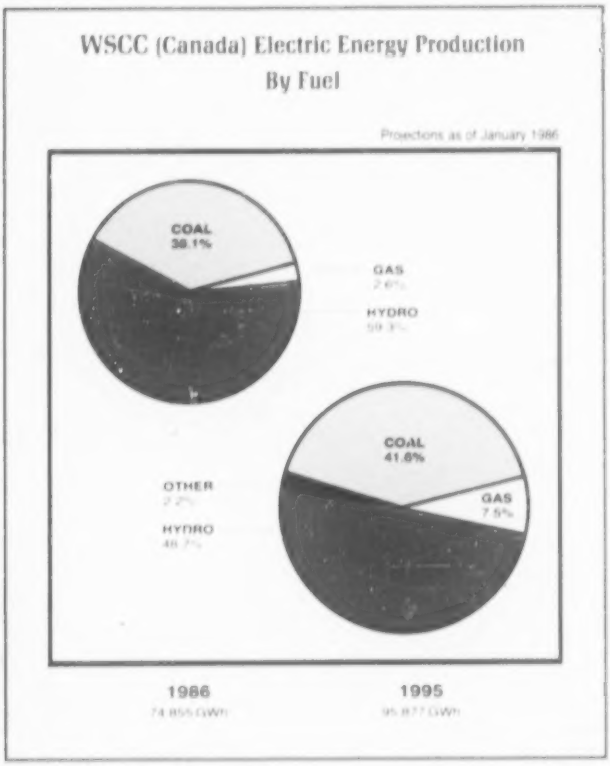
Arizona-New Mexico Power Area

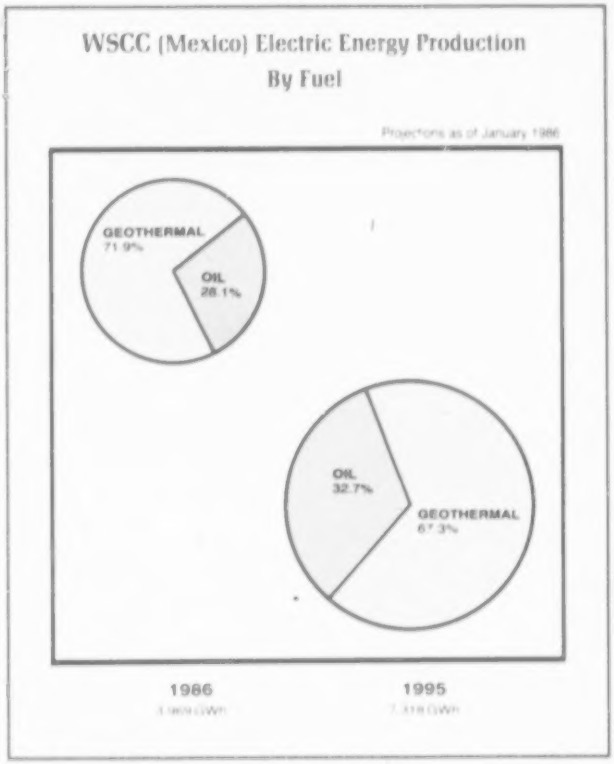
The Arizona-New Mexico Power Area consists of Arizona, most of New Mexico and the westernmost part of Texas. The accompanying table depicts this year's forecast of peak demand and energy as compared to last year's forecast. Generating capacity margins during summer peak range between 23% and 31% for the next 10 years.

Projected net generating capacity additions for the 1986-1995 period total approximately 5,014 MW and are predominately coal-fired and nuclear units.

The 3-unit Palo Verde nuclear generating plant located in southwestern Arizona is progressing steadily. The 1,270 MW Palo Verde Unit No. 1 began firm power operation in early 1986. The remaining two 1,270 MW units are expected to be placed in commercial operation during the third quarter of 1986 and 1987, respectively. The Arizona-New Mexico area's share of the Palo Verde nuclear plant represents approximately 40% of the area's planned net generating capacity additions over the next 10-year period.

Although the Arizona to California transmission system has been strengthened, the Four Corners to Central Arizona





Arizona-New Mexico Power Area
Comparison of Forecasts

	This Year's Forecast (1986-1995)	Last Year's Forecast (1985-1994)
10-Year Forecasts:		
Summer Peak Demand Growth Rate (% yr)	3.6	4.0
Annual Energy Growth Rate (% yr)	3.3	4.3
Forecasts for Year 1994:		
Summer Peak Demand MW	13,971	14,368
% Change	-2.8	
Annual Energy GWh	68,341	68,134
% Change	0.3	

transmission system has not, and it is believed that clockwise loop flow will increasingly inhibit power schedules from the Four Corners area power plants to their respective Arizona California owners.

With the continuing economic incentives for California utilities to maximize imports, the use of sophisticated remedial action schemes such as generator tripping in the Northwest and planned islanding in the Southwest is being expanded as a means to increase the power transfer limits from the Northwest into California. Should these remedial action schemes fail to operate as planned, the adverse effect on the Arizona-New Mexico Power Area is a matter of serious concern. The Arizona-New Mexico utilities are actively working with California entities, both directly and through WSCC, to assure that the present remedial action schemes, along with the application of additional remedial action schemes, will not degrade the reliability and security of the Arizona-New Mexico area.

The transfer capability between Arizona and California is expected to increase to approximately 5,500 MW by 1987. This projected increase, coupled with the increased transfer capability proposed for the Northwest to California transmission system for the same time period, requires the use of seasonal operating nomograms and close coordination of many system operating limits.

California-Southern Nevada Power Area

The California-Southern Nevada Power Area is composed of California, southern Nevada and the northern portion of Baja California, Mexico.

The accompanying table presents this year's forecast of summer peak demand and energy for the U.S. portion of the area as compared to last year's forecast. Generating capacity margins during summer peak range between 21% and 24% for the next 10 years.

California-Southern Nevada Power Area (U.S.) Comparison of Forecasts		
	This Year's Forecast (1986-1995)	Last Year's Forecast (1985-1994)
10-Year Forecasts:		
Summer Peak Demand Growth Rate (%/yr)	2.1	2.1
Annual Energy Growth Rate (%/yr)	2.2	2.1
Forecasts for Year 1994:		
Summer Peak Demand — MW	49,992	48,464
% Change	3.2	
Annual Energy — GWh	255,087	250,314
% Change	1.9	

The 1,073 MW Diablo Canyon Nuclear Unit No. 1 began commercial operation in April 1985 and Diablo Canyon Unit No. 2 (1,105 MW) in early 1986. During 1985, over 750 MW of alternative and renewable generation resources were placed in service within the area.

Over the next 10 years, the California-Southern Nevada Power Area will be exposed to a number of interrelated factors which will affect overall system reliability. These factors have been discussed previously within this report and include the following:

- The increase in the capability of the ac and dc Pacific Interties.
- The increase in the capability of the Arizona-California transmission system.
- The addition of the Intermountain Power Plant and associated dc transmission.
- The continuation of interarea transfers to maximize operating efficiency.
- The reliability of remedial action schemes.
- The effects of cogeneration additions.

These factors and others, as mentioned under the various individual area headings, illustrate the necessity for continual coordination of planning and operation to achieve an acceptable level of interconnected system reliability.

Western Systems Coordinating Council (WSCC), with 60 member systems and 4 affiliates, encompasses approximately 1.8 million square miles of territory in 14 western states plus parts of 2 Canadian provinces and the northern portion of Baja California, Mexico. The Region is characterized by extremes in population and load densities in addition to long distances between load centers and power generation sources. The Region is subdivided into 4 areas, namely: the Northwest Power Pool Area, which is winter peaking and heavily dependent on hydro generation; the Rocky Mountain Power Area, which is either summer or winter peaking with a 26% hydro and 62% coal-fired generation mix; the Arizona-New Mexico Power Area, which is summer peaking with a 35% gas/oil and 59% coal-fired generation mix; and the California-Southern Nevada Power Area, which is summer peaking and heavily dependent on gas- and oil-fired generation.

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1987 RELIABILITY ASSESSMENT

THE FUTURE OF BULK ELECTRIC SYSTEM RELIABILITY IN NORTH AMERICA 1987–1996

SEPTEMBER 1987

North American
Electric
Reliability
Council

North American Electric Reliability Council

ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interconnected Network

MAPP
Mid-Continent Area Power Pool

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WSCC
Western Sytems Coordinating Council

AFFILIATE

ASCC
Alaska Systems Coordinating Council

The North American Electric Reliability Council (NERC) was formed in 1968 by the electric utilities to promote the RELIABILITY of their generation and transmission systems. NERC consists of nine Regional Reliability Councils and one affiliate encompassing virtually all of the electric systems in the United States, Canada, and the northern portion of Baja California, Mexico.

RELIABILITY, in a bulk electric system, is the degree to which the performance of the elements of that system results in electricity being delivered to customers within accepted standards and in the amount desired. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply (or service to customers.)

Bulk electric system reliability can be addressed by considering two basic and functional aspects of the bulk electric system — adequacy and security.

ADEQUACY is the ability of the bulk electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system components.

SECURITY is the ability of the bulk electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

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1987 Reliability Assessment

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Executive Summary

Our society increasingly depends on a reliable supply of electricity. Even though the 10-year supply plans of the electric utilities are judged to be adequate, this assessment can change. Obstacles to carrying out these plans, and the possibility that customers could demand more electricity than the plans will support raise serious reliability threats to electric supply. To provide a basis for responsible action, policy makers need to recognize and understand the threats to future reliability.

Utility Plans Will Support The Most Likely Growth

Utility plans will support an average annual growth in the demand for electricity of 2% in the United States and 2.7% in Canada. These are the most likely 10-year growth rates. However, there is a 50% chance that growth will be greater.

Threat: Growth may be greater than utility plans can support.

Additions May Be Delayed

Construction has not yet started on 44% (31,200 MW utility-owned, 9,800 MW non-utility-owned) of the new generating units expected by 1996. Construction has also not started on nearly 20,000 miles of planned high voltage transmission lines. Much of this construction will not be completed on schedule because of inconsistent and drawn-out regulatory actions, construction delays, pressure to reduce expenditures, and changing environmental legislation.

Threat: If all new generating and transmission facilities are not in service when planned, even the "most likely" growth cannot be reliably supported.

Existing Facilities Must Continue To Operate

Utility plans depend on the continued operation of 183,000 miles of high voltage transmission lines and 716,000 MW of existing generating capacity. Nearly 27% of this capacity is oil- or natural gas-fired, 42% coal-fired, and 13% nuclear. The remainder is primarily hydro.

Threat: Environmental legislation and rules, continuing challenges to the operation of nuclear units, disruptions of fuel supplies, and the aging of equipment may limit or prevent the operation of existing facilities.

Dependence On Load Management And Non-Utility Generation Is Growing

By 1996, utilities plan to use load management to curtail up to 3% of their customers' demand. The utilities' electric supply plans also anticipate 25,300 MW of non-utility generation by 1996 which will amount to 3.5% of the total capacity resources in the United States and 0.6% in Canada.

Threat: The availability and effectiveness of both load management and non-utility generation over the long-term remain to be proven.

Transmission Is Critical

The present and future interconnected transmission systems are heavily committed to capacity and energy transactions among utilities. To accommodate transactions beyond those already planned — by either utilities or non-utility generators — utilities will need to build additional transmission facilities.

Threat: The lengthy licensing processes and the disincentives inherent in the current regulatory process create formidable impediments to constructing new transmission.

Deregulation Is An Unknown

Deregulation may result in utilities competing more and coordinating less. The highly reliable electric systems of North America are the result of extensive planning and operating coordination among utilities over many years.

Threat: Because of antitrust concerns and competitive conditions, utilities may begin to withhold from each other the very information needed for coordination to maintain reliability.

Responsible Regulation Is A Key To Reliability

Regulatory actions often constrain the operation and planning of electric supply facilities.

Threat: Overlapping jurisdictions, disputes over interpretations of regulations, and reversals of prior rulings can lead to lower reliability.

Lower Reliability Affects All Customers

When a reliable electric supply to all customers cannot be maintained, utilities must apply emergency procedures to protect the integrity of the overall system, even if this means interrupting service to certain customers. A decrease in reliability will lead to an increase in the frequency and extent of customer interruptions.

Threat: The public may be forced to accept a lower level of reliability. The time needed to reestablish a reliable electric supply could be several years.

A reliable supply of electricity is crucial to our society. Any savings achieved at the expense of reliability must be weighed against the potential damage to our economy, our standard of living, and the security of our nations. Electric utilities, regulators, government officials, customers, and indeed all North Americans must recognize and understand these threats and take responsible action to assure future electric reliability.

Foreword

About the Council

The North American Electric Reliability Council (NERC) was formed in 1968 by the electric utilities to promote the RELIABILITY of their generation and transmission systems. NERC consists of nine Regional Reliability Councils and one Affiliate encompassing virtually all of the electric utility systems in the United States, Canada, and the northern portion of Baja California, Mexico.

The governing body of the Council is its Board of Trustees. It consists of two representatives from each Regional Reliability Council plus additional Trustees as necessary to assure at least one representative from a Canadian utility system and at least two representatives from each segment of the electric utility industry: investor-owned, Federal, rural electric cooperative, and state/municipal.

Meetings of the Board are attended by observers from the United States Department of Energy, the United States Federal Energy Regulatory Commission, the Canadian National Energy Board, the Edison Electric Institute, the American Public Power Association, the National Rural Electric Cooperative Association, and the Canadian Electrical Association.

The overall activities of the Council are directed by its Board of Trustees. Its technical activities are carried out by its Operating and Engineering Committees and their subgroups comprised of managerial and technical experts from the nine Regional Reliability Councils. The NERC staff, located in Princeton, New Jersey, provides coordination and support for the Council's overall activities.

About this Report

The NERC Board of Trustees created the Interregional Review Subcommittee (IRS) in 1970 to review, on a continuing basis, the overall reliability of the existing and planned generation and transmission systems of the nine Regional Reliability Councils.

This 1987 Reliability Assessment report presents:

- An assessment of electric supply reliability through 1996
- A discussion of the key factors and issues affecting future electric supply, and
- Detailed region-by-region assessments of electric supply reliability, including those issues of specific regional concern.

In preparing this report, the IRS interviewed representatives of selected regions and various industry experts. They reviewed detailed self-assessments prepared by each of the nine Regional Reliability Councils, and aggregate forecasts of peak demand and planned capacity resources on a regional and national basis. They also appraised regional plans and commitments for future electric generation and transmission facilities, and assessed the potential effect of legislation, regulations, and governmental policies on future electric supply reliability. This report is the culmination of these efforts and reflects the expertise, judgment, and interpretations of the IRS members.

Unless otherwise noted, the data presented in the figures and tables reflect conditions as of January 1, 1987. Data has been extracted from the April 1, 1987 Coordinated Bulk Power Supply Program (IE-411) Reports submitted to the United States Department of Energy by each Regional Reliability Council and from other Regional data submittals made directly to the IRS. Detailed background information on projected peak demands, annual energy requirements, generating capabilities, transmission, and fossil fuel requirements are presented in a companion report by the North American Electric Reliability Council — "1987 Electricity Supply & Demand for 1987-1996."

Peak Demand and Energy

Ten-year projections of peak demand and annual energy are slightly lower in the United States and slightly higher in Canada than those made last year.

The uncertainty in the projections of a 2% per year average growth in peak demand in the United States and 2.7% per year in Canada can be illustrated by the high and low bands around these base 10-year forecasts. For the United States, these bands indicate that there is an 80% probability that peak demand will increase at an annual rate between 0.9% and 3.3% over the 1987-1996 period. For Canada, the increase will be between 1.6% and 3.3%.

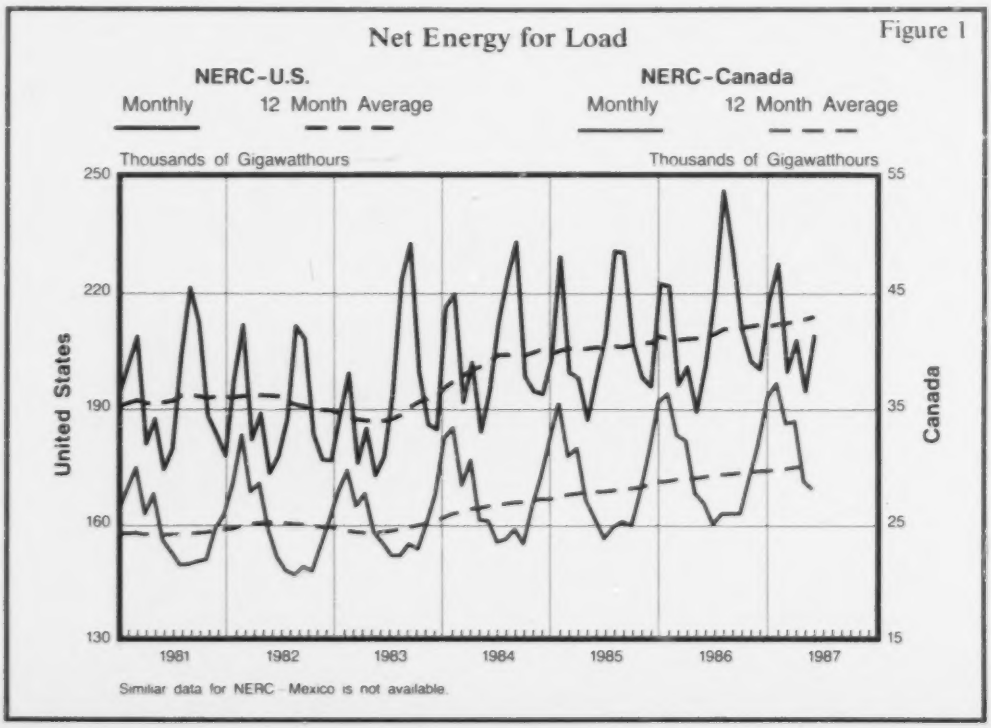
Utilities in all regions are using load management programs to reduce system peak demands and to defer the need for generating capacity additions. More experience will be required to establish the long-term availability, cost effectiveness, and customer acceptance of many of these programs.

1986 Experience

Table 1 compares the actual peak hour demands and annual electrical energy generated in 1986 with those of 1985 and with the values previously forecast for 1986 for the NERC areas of the United States, Canada, and Mexico.

The 1986 actual summer peak demands equaled or exceeded the 1985 summer peaks in all three NERC areas. However, only the United States exceeded its 1986 summer peak demand forecast.

Figure 1



The 1986/87 winter peak demands were generally depressed in all three areas because of a mild winter. The winter peak in Canada equaled the 1985/86 winter peak, while in the United States and the NERC portion of Mexico, the 1986/87 winter peaks did not reach the previous winter's peak demands. Actual 1986/87 winter peak demands fell below forecast in all areas.

The 1986 net electrical energy for load in the United States exceeded 1985's energy by 1.3% and the 1986 forecast by 0.3%. In Canada, the 1986 net electrical energy for load exceeded both the 1985 actual and 1986 forecast values. In the NERC portion of Mexico, the 1986 energy was 8.5% greater than in 1985 but was 4.6% less than forecast.

Figure 1 shows the monthly and twelve-month running average energy for load beginning in 1981 for the United States and Canada. Figure 2 shows that the twelve-month running average growth rates for energy have stabilized somewhat in the past two years.

Table 1 — 1986 Actual Peak Demand and Energy Experience

	1985 Actual	1986 Actual	Actual Change %	1986 Forecast	Actual vs Forecast %
NERC — U.S.					
Summer Peak Demand (Thousands of MW)	461	477	3.6	475	0.4
Winter Peak Demand (Thousands of MW)	429	423	-1.4	435	-2.7
Annual Net Energy for Load (Millions of MWh)	2499	2532	1.3	2525	0.3
NERC — Canada					
Summer Peak Demand (Thousands of MW)	45	47	4.4	47	-0.3
Winter Peak Demand (Thousands of MW)	64	64	0.1	65	-1.1
Annual Net Energy for Load (Millions of MWh)	345	357	3.4	350	1.9
NERC — Mexico[a]					
Summer Peak Demand (Thousands of MW)	0.62	0.62	0.0	0.64	-3.9
Winter Peak Demand (Thousands of MW)	0.40	0.39	-1.0	0.42	-5.5
Annual Net Energy for Load (Millions of MWh)	2.61	2.83	8.5	2.97	-4.6

[a]Includes only that part of the Comision Federal de Electricidad system in the northern portion of Baja California, Mexico, which is interconnected with the U.S. systems.

Figure 2

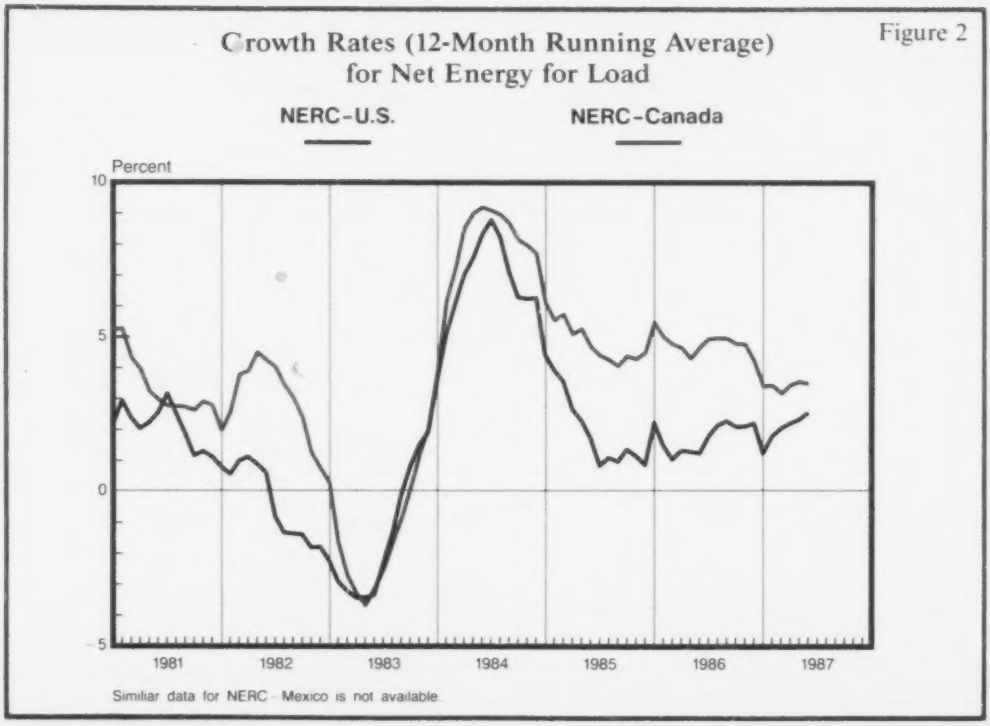


Table 2 — 1987-1996 Forecast of Peak Demand and Energy	NERC U.S.	NERC Canada	NERC Mexico[a]	NERC Total
Summer Peak Demand (Thousands of MW)				
1987	484	49	0.7	534
1996	577	63	1.2	641
Average Growth (%/year)	2.0	2.7	6.6	2.0
Winter Peak Demand (Thousands of MW)				
1987/88	444	68	0.4	512
1996/97	534	86	0.8	621
Average Growth (%/year)	2.1	2.7	6.6	2.2
Annual Net Energy for Load (Millions of MWh)				
1987	2589	374	3.2	2966
1996	3116	484	5.9	3606
Average Growth (%/year)	2.1	2.9	6.8	2.2

[a]Includes only that part of the Comision Federal de Electricidad system in the northern portion of Baja California, Mexico, which is interconnected with the U.S. systems.

1987-1996 Forecast

The aggregated peak demand and annual energy projections over the 1987-1996 period are summarized in Table 2 for the United States, Canada, the NERC portion of Mexico, and for NERC as a whole. The United States is summer peaking but with a winter peak demand growing at a slightly faster rate than the summer demand. Canada will continue to be winter peaking throughout the forecast period with summer and winter peaks projected to increase at about the same rate.

In all three areas of NERC, the projected 1987-1996 growth rates for annual energy are equal to or higher than the growth rates for peak demand. This trend will result in higher annual load factors and increased utilization of existing and future facilities. The influence of load management and conservation affects forecasts in all regions. The extent to which utility-controlled load management programs may affect peak demands is discussed in a later section of this chapter.

Similar peak demand and annual energy forecast data for each of the nine Regional Reliability Councils are presented in the regional chapters of this report.

Comparison of Recent Forecasts

Table 3 compares the 1987-1996 forecast average annual growth rates with those of last year's forecast. The current forecast growth rates for peak demand and annual net energy for load are slightly lower in all three areas of NERC as well as for NERC as a whole.

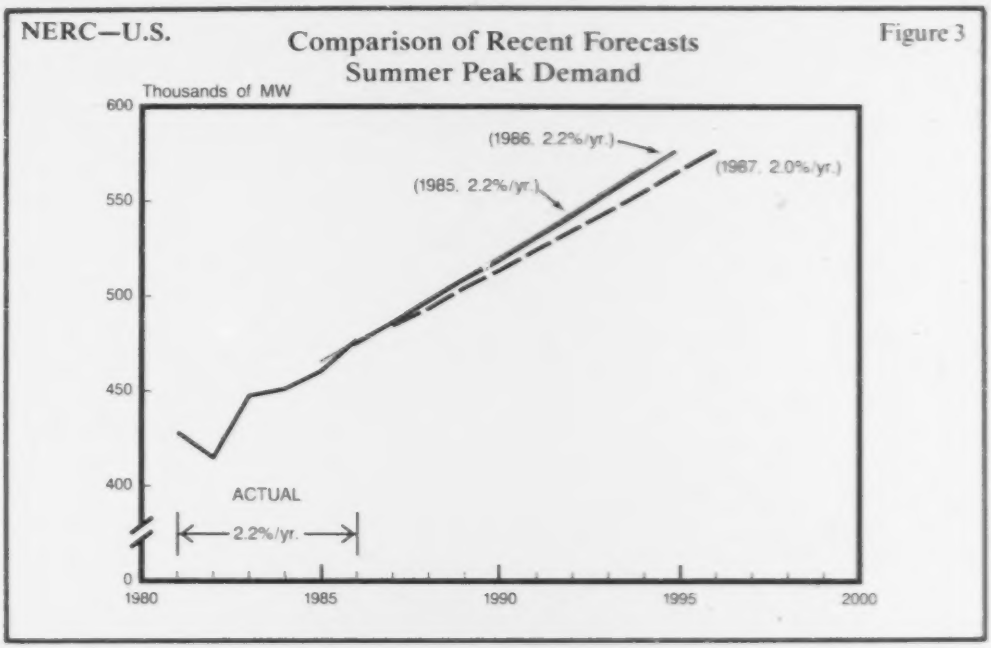
Table 3 — Comparison of Forecast Growth Rates (%/Year)	NERC U.S.	NERC Canada	NERC Mexico[a]	NERC Total
Summer Peak Demand				
This Year (1987-1996)	**2.0**	**2.7**	**6.6**	**2.0**
Last Year (1986-1995)	2.2	3.0	7.1	2.3
Winter Peak Demand				
This Year (1987-1996)	**2.1**	**2.7**	**6.6**	**2.2**
Last Year (1986-1995)	2.3	2.8	7.1	2.4
Annual Net Energy for Load				
This Year (1987-1996)	**2.1**	**2.9**	**6.8**	**2.2**
Last Year (1986-1995)	2.3	3.1	7.3	2.4

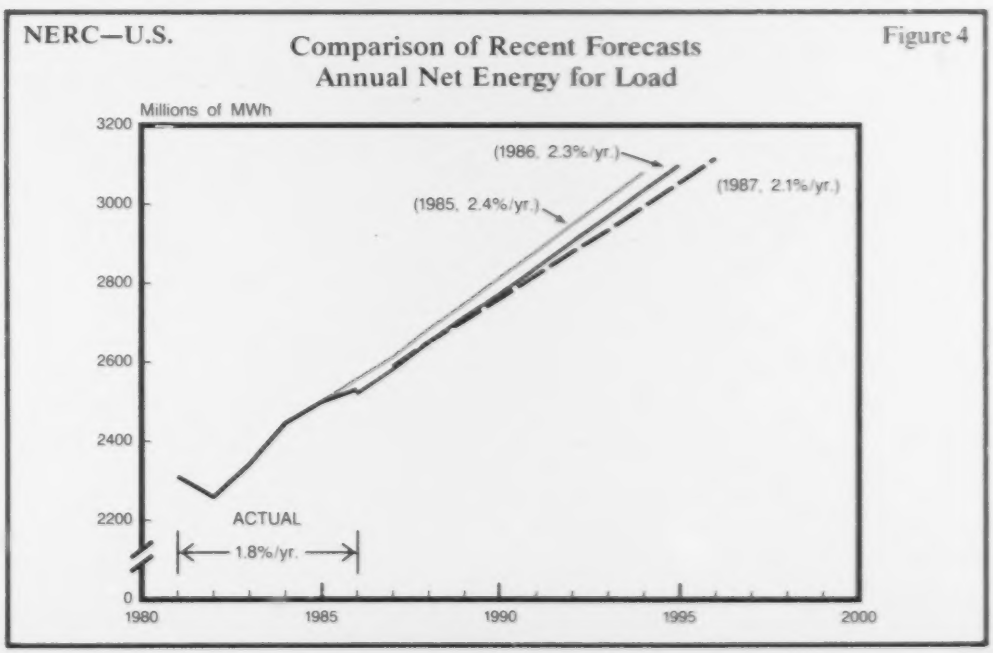
[a]Includes only that part of the Comision Federal de Electricidad system in the northern portion of Baja California, Mexico, which is interconnected with the U.S. systems.

Figures 3,4,5 and 6 further compare the base peak demand and net energy for load 10-year forecasts made in 1985, 1986, and 1987 for the United States and Canada. In the United States, both the summer peak demand and annual energy projections are slightly lower than in the previous two forecasts. In contrast, in Canada, both the winter peak demand and annual energy projections are slightly higher than the forecasts made in 1985 and 1986.

Forecast Uncertainty

The base forecasts for peak demand and annual energy are aggregates of the most probable forecasts of each of the member utilities. It is intended that the likelihood of exceeding the base forecast is equal to the likelihood of the forecast not being reached. That is, there is a 50%





chance that the base forecasts will be exceeded and a 50% chance that the base forecasts will not be reached.

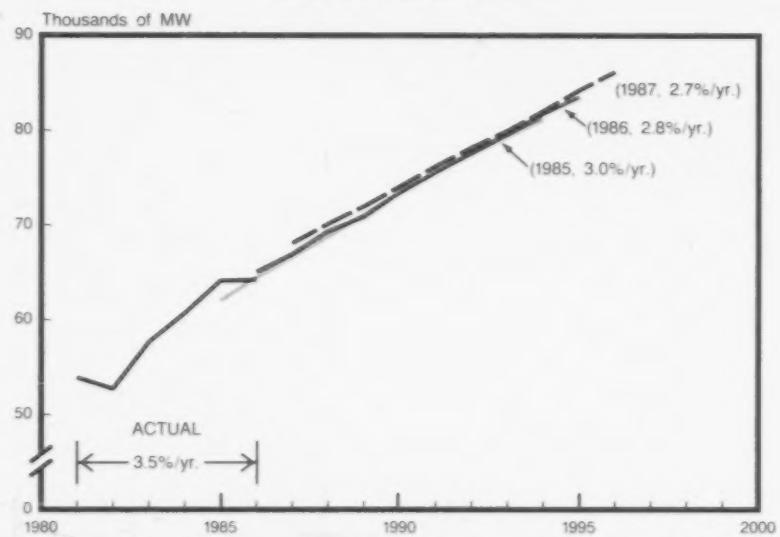
Because electric demand and annual energy consumption are reflections of the ways in which people use electricity in their domestic, commercial, and industrial activities, the utilities' forecasts are subject to change. To avoid implying a degree of certainty not intended in the base forecasts, bands of reasonable variation from forecast have been defined.

The bands, or sensitivity bandwidths, for the 1987-1996 aggregated base forecasts for the United States and Canada are shown by the shaded areas of Figures 7, 8, 9 and 10. These figures also show historical average annual growth rates. In developing the U.S. bandwidths, the var-

NERC—Canada

Figure 5

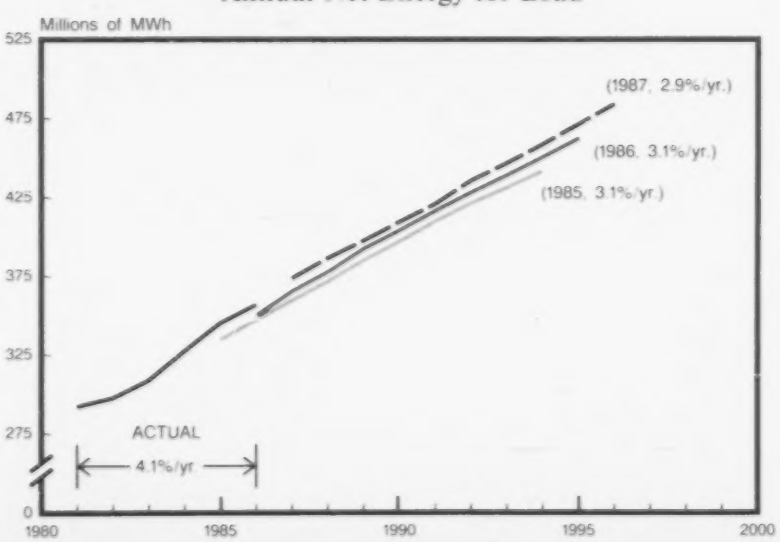
Comparison of Recent Forecasts
Winter Peak Demand



NERC—Canada

Figure 6

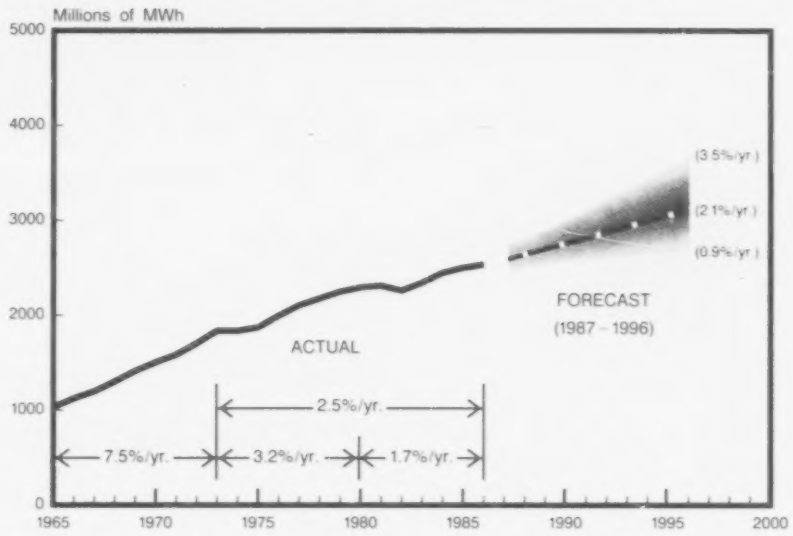
Comparison of Recent Forecasts
Annual Net Energy for Load



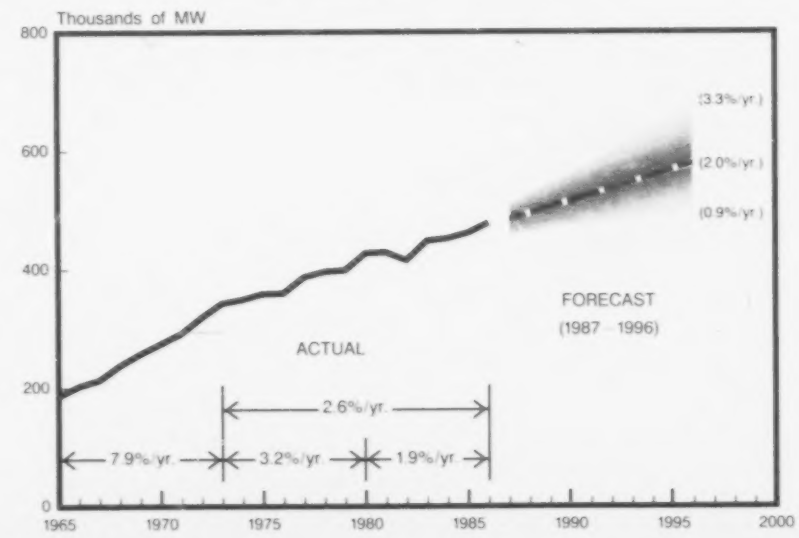
iables which were found to relate best to growth in electrical energy were the real gross national product, the real price of electricity, and the real price of natural gas.

Relationships between these variables and annual net energy for load were established. High and low estimates of the variables were then selected to develop high and low annual energy projections about the base annual energy forecast as shown in Figure 7. There is an 80% probability that future annual net energy for load for the United States will fall within the shaded area. The upper bound of the shaded area implies an annual average growth rate of 3.5%, while the lower bound indicates a 0.5% per year rate. There is a 10% chance that future annual energy for load requirements will exceed the upper bound, and a 10% chance that annual energy needs will

NERC—U.S. Annual Net Energy for Load Bandwidths Figure 7



NERC—U.S. Summer Peak Demand Bandwidths Figure 8



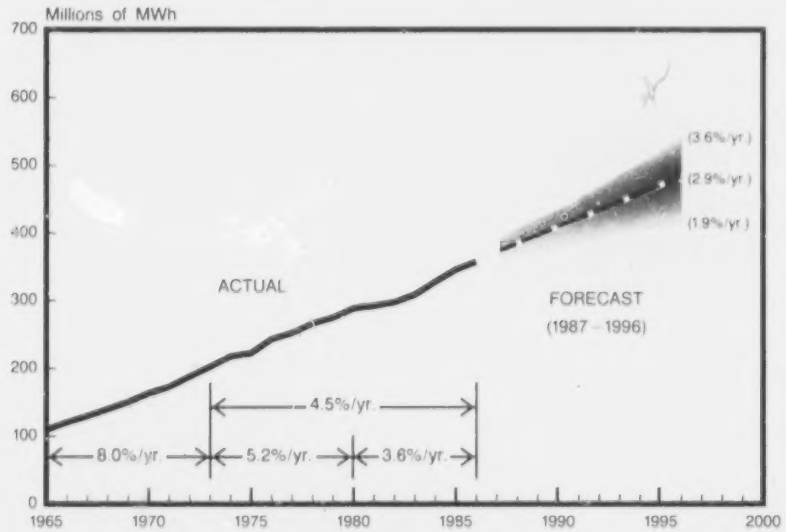
be less than the lower bound. The summer peak demand ranges of Figure 8 were estimated by applying the annual load factors from the NERC aggregated base forecasts to the high and low energy bands of Figure 7 along with consideration of the historical relation between peak demand and annual energy. The resulting 80% probability range of peak demand growth rates for the United States is 0.9% to 3.3% per year.

The 80% bandwidths for the Canada base forecasts of annual net energy for load and winter peak demand are shown in Figures 9 and 10, respectively. The predictor variables used in the Canadian energy model were the real domestic national product, the real price of electricity, a weighted average of the real price of natural gas and oil, and the effect of marketing efforts in the industrial sector. The resulting ranges of average growth rates in Cana-

NERC—Canada

Figure 9

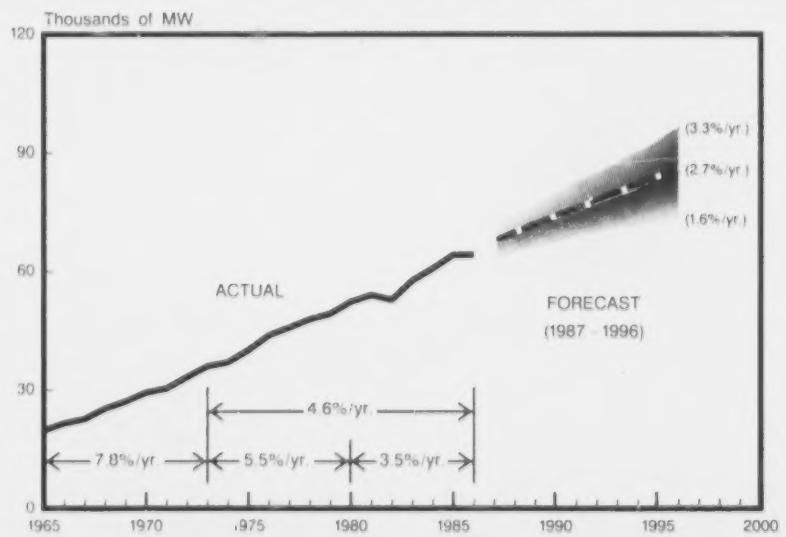
Annual Net Energy for Load Bandwidths



NERC—Canada

Figure 10

Winter Peak Demand Bandwidths



Load Management

In this report, the term "load management" includes those technologies, methodologies, procedures, and equipment for reducing load (peak demand) on electric utility systems. It includes only those customer loads either under the direct control of the utility system operator or interruptible by the customer at the utility's request in accordance with contractual arrangements.

Actual interruption of the electric supply to particular equipment or facilities on a customer's premises is usually accomplished by a radio signal or request from a utility. The demand reductions are generally achieved within minutes but may take up to a few hours. The direct switching of water heaters, air conditioners, or irrigation pumps are typical examples of loads which are controlled.

Load management as defined here does not include load reductions achieved without utility control, such as customer response to incentives embodied in rate design, utility conservation programs, and other similar programs.

da are 1.9% to 3.6% per year for annual energy and 1.6% to 3.3% per year for peak demand.

The Canada and U.S. forecast bandwidth calculation methodologies are similar except for the variables.

It would be incorrect and misleading to apply the ranges of the forecast bandwidths shown in Figures 7, 8, 9 and 10 to the forecasts of any of the nine NERC Regional Reliability Councils or to the forecasts of individual utilities since the bands shown represent a composite of all member utilities in each country.

Load Management

As mentioned earlier, some utilities in all regions of NERC have included the effects of load management programs in their ten-year forecasts. These programs provide the utility with the ability to reduce peak demands and thus possibly delay the need for some future electric generating capacity.

A 1987 NERC survey of electric utility load management activities indicated that load management is being employed in various degrees throughout NERC. A significant portion of anticipated load management effects have already been applied to reduce peak demand projections. The following survey results should not, therefore, be subtracted from the peak demand forecast in order to arrive at net demand values. About 9,200 MW of the U.S. summer peak demand is now under load management. This amount is the equivalent of 1.9% of the 1986 U.S. summer peak demand. Similarly, the equivalent of about 2% of Canada's 1986/87 winter peak demand, or about 1,300 MW, is under utility load management. The survey also indicated a considerable increase in load management activities by utilities over the next 10 years. By 1996, the equivalent of about 2.9% of the U.S. 1996 summer peak demand, or 16,500 MW, will be included in active load management programs. In Canada, these programs will affect 2,900 MW or the equivalent of about 3.4% of Canada's 1996/97 winter peak demand. Utilities indicate a confidence level of over 70% that these programs will be in operation by 1996.

Some utilities are initiating programs now as a means of gaining experience with load management, or to provide flexibility in the future. Other utilities will be heavily dependent on the success of load management programs in satisfying their capacity margin requirements five to ten years from now.

Load management is not an unlimited resource. It may reduce the rate of growth in peak demand, but it will not eliminate growth. Although it is too early in the development of this technology to give a precise figure, a NERC survey of load management experts indicated that the average reduction of peak demand is unlikely to ever exceed 10% on a national basis. A reduction in the range of 3% to 6% is estimated to be much more likely. The long-term effects and availability of load management have yet to be proven.

Generating Capacity

Planned capacity additions over the 1987-1996 period are 79,300 MW in the United States and 13,100 MW in Canada. These planned additions are less than last year's 10-year projected additions by about 7,400 MW in the United States and 700 MW in Canada. The 500 MW of planned additions in the NERC portion of Mexico are the same as last year's projections.

Of the total planned capacity additions, about 35,400 MW (45%) in the United States and 5,400 MW (41%) in Canada are not yet under construction. About 9,800 MW, or 24% of the capacity not yet under construction, are coal-fired steam units of 100 MW or larger. It is likely that some of these units will not be completed as scheduled.

Non-utility generation is projected to account for 11,500 MW or 14.4% of the planned capacity additions over the next 10 years in the United States, and about 240 MW or 1.8% of the additions in Canada. By 1996, non-utility generating capacity will equal about 25,300 MW or 3.1% of NERC's total summer capacity resources.

Recent Experience

The total installed generating capacity, as shown in Table 4, increased in the NERC areas of the United States, Canada, and Mexico by 11,700 MW (1.9%), 1,400 MW (1.8%), and 200 MW (31.8%), respectively in 1986 over 1985. The electrical energy generated by the total installed capacity from primary energy sources (pumped storage generation and net imports excluded) increased in 1986 to 2,495 million MWh in the United States, to 361 million MWh in Canada, and to 4.2 million MWh in Mexico. The actual 1986 electrical energy production for the United States exceeded 1985's production by 2.3% and the 1986 forecast by 1.2%. Canada's electrical energy production exceeded 1985's production by 1.8% and its 1986 forecast by 1.8%. The NERC portion of Mexico exceeded its 1985 production by 57.9% and its 1986 forecast by 5.6%.

Table 4 — 1986 Installed Generating Capacity and Electrical Energy Production

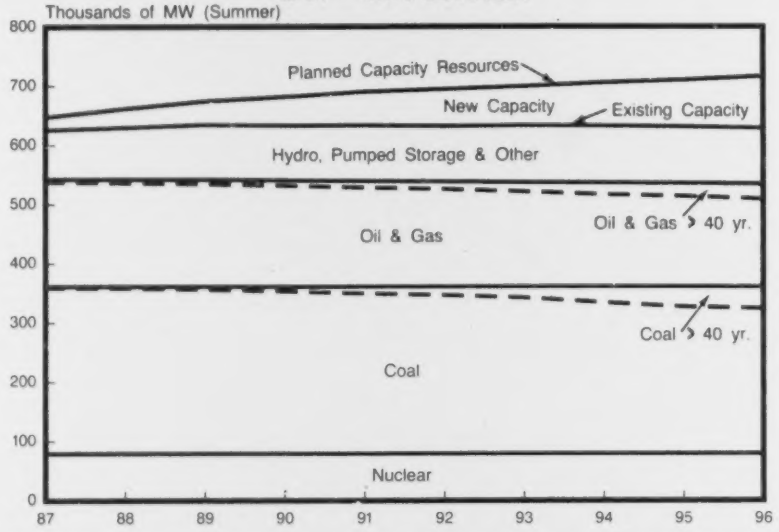
	1985 Actual	1986 Actual	Actual Change %	1986 Forecast	Actual vs Forecast %
NERC — U.S.					
Generating Capacity — Summer (Thousands of MW)	621.6	633.3	1.9	633.2	<0.1
Electrical Energy Production[a] (Millions of MWh)	2438.4	2495.2	2.3	2464.9	1.2
NERC — Canada					
Generating Capacity — Winter (Thousands of MW)	80.7	82.1	1.8	83.6	-1.8
Electrical Energy Production[a] (Millions of MWh)	354.3	360.6	1.8	354.4	1.8
NERC — Mexico[b]					
Generating Capacity — Summer (Thousands of MW)	0.6	0.8	31.8	0.9	-10.8
Electrical Energy Production[a] (Millions of MWh)	2.7	4.2	57.9	4.0	5.6

[a]Total electrical energy produced by primary energy sources (pumped storage generation and net imports are excluded).

[b]Includes only that part of the Comision Federal de Electricidad system in the northern portion of Baja California, Mexico, which is interconnected with the U.S. systems.

NERC—U.S. Figure 11

Existing and Planned Capacity Resources by Type
1987—1996 Forecast



1987-1996 Projections

Projections of generating unit additions, retirements, and oil-to-coal conversions during the 1987-1996 forecast period are summarized in Table 5. Planned capacity additions of 92,900 MW for NERC are about 8,100 MW less than last year's 10-year (1986-1995) forecast.

Projected generating unit retirements in NERC of 10,600 MW (10,400 MW in the United States and 200 MW in Canada) are approximately 11% less than last year's 10-year retirement projections. Oil-to-coal conversions are expected to total 1,700 MW in the 10-year period, indicating an increase of about 21% over last year's projected conversions. The increased attention given to extending

NERC—Canada Figure 12

Existing and Planned Capacity Resources by Type
1987—1996 Forecast

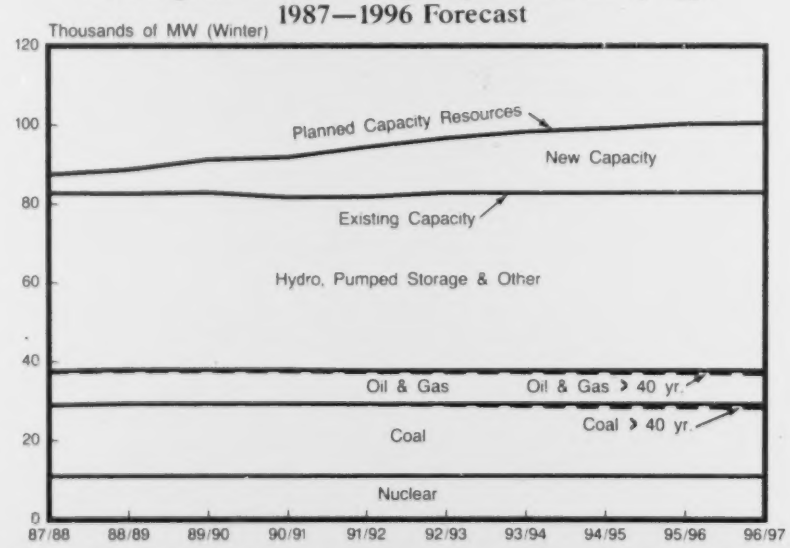


Table 5 — NERC Generating Unit Additions, Retirements and Conversions (1987—1996)

	NERC-U.S.		NERC-Canada		NERC-Mexico[a]		NERC-Total	
Type	Thousands of MW	% of Total	Thousands of MW	% of Total	Thousands of MW	% of Total	Thousands of MW	% of Total
Nuclear	25.3[b]	31.9	4.4	33.3	0.0	0.0	29.7[b]	32.0
Coal	22.7	28.6	3.3	25.5	0.0	0.0	26.0	28.0
Hydro	2.5	3.2	4.7	35.8	0.0	0.0	7.2	7.8
Oil/Gas	9.5	12.0	0.5	3.6	0.3	59.2	10.3	11.1
Pumped Storage	2.4	3.0	0.0	0.0	0.0	0.0	2.4	2.6
Other (Utility)	5.4	6.9	0.0	0.0	0.2[c]	40.8	5.6	6.0
Non-Utility Generation[d]	11.5	14.4	0.2	1.8	0.0	0.0	11.7	12.5
Additions	79.3	100	13.1	100	0.5	100	92.9	100
Retirements	10.4		0.2		0.0		10.6	
Conversions (Oil-to-Coal)	1.2		0.5		0.0		1.7	

[a]Includes only that part of the Comision Federal de Electricidad system in the northern portion of Baja California, Mexico, which is interconnected with the U.S. systems.

[b]Perry 2, WNP1, and WNP3 nuclear units are not included.

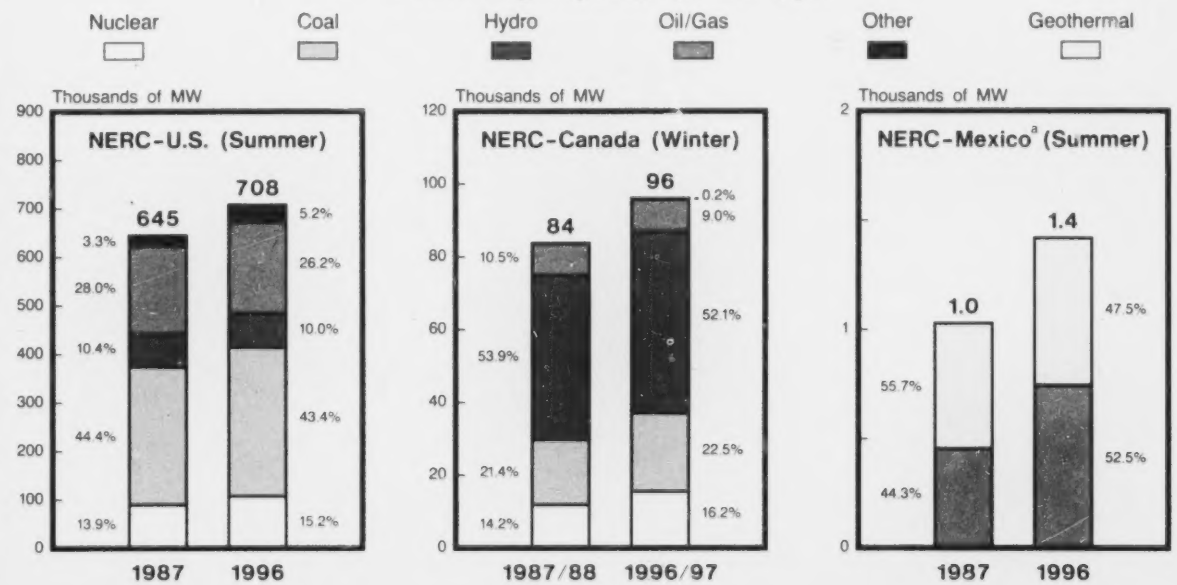
[c]All geothermal capacity.

[d]Of the total, 3,091 MW (U.S.) and 240 MW (Canada) are reported to be cogeneration capacity.

the life of existing units and to improving availability is influencing decisions on capacity additions, deferrals, cancellations, and retirements.

Coal and nuclear generating units account for 60.5% of the U.S. planned capacity additions over the forecast period. All other types of utility-owned generation will comprise another 25.1%, while non-utility generation facilities will provide the remaining 14.4%. In Canada, nuclear, hydro and coal generating units will comprise 94.6% of the capacity additions. The NERC portion of Mexico is projecting only oil and geothermal unit additions.

Figure 13



[a] Includes only that part of the Comision Federal de Electricidad system in the northern portion of Baja California, Mexico, which is interconnected with the U.S. systems.

The existing capacity by fuel type and the planned additional capacity resources for the United States and Canada over the forecast period are indicated in Figures 11 and 12, respectively. By 1996, these new capacity resources will account for 12% of the total capacity resources in the United States and about 18% of the total capacity resources in Canada. Figures 11 and 12 also show the amount of coal and oil and gas capacity greater than 40 years old.

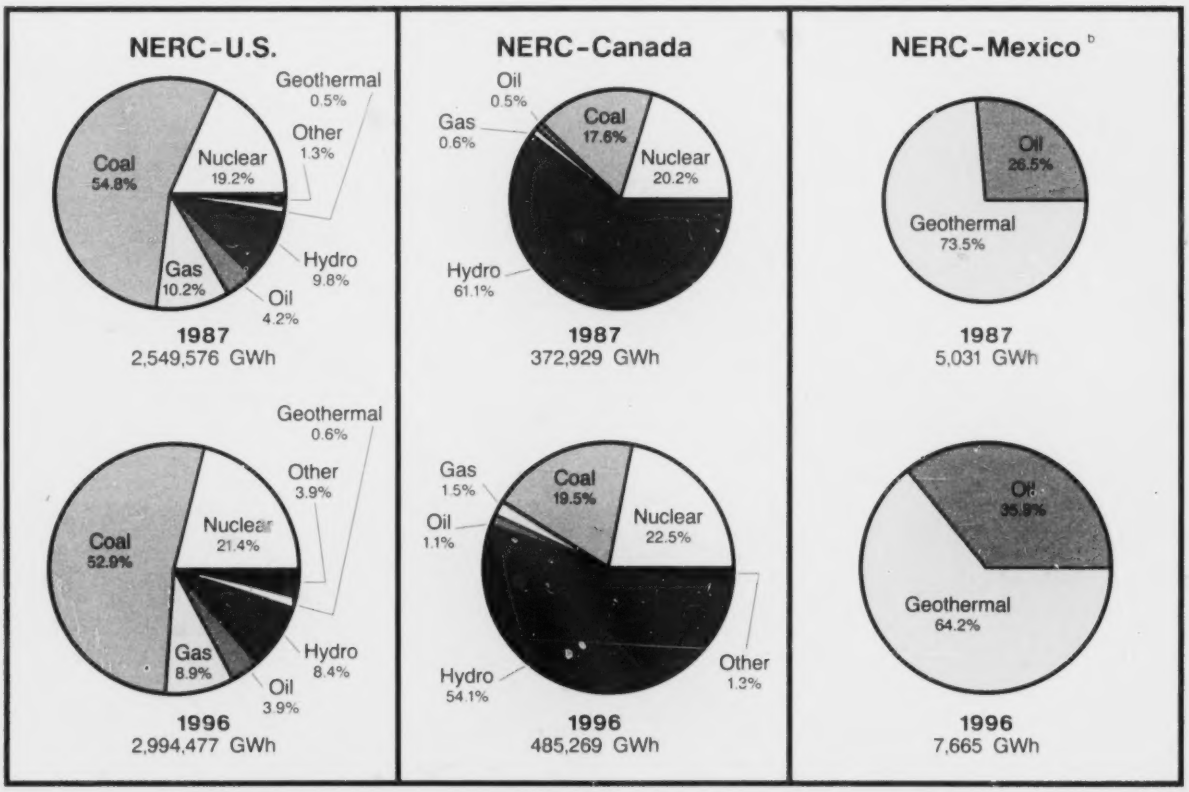
Figure 13 shows the generating capacity, segregated by fuel type, in 1987 and 1996, and indicates the overall effect of unit planned additions, retirements, conversions and reratings. Over the next few years, the completion of nuclear units already under construction will dominate capacity additions in the United States and Canada. During the latter half of the forecast period, U.S. additions will shift to coal units. In Canada, the shift will be mainly to hydro capacity. Present and future capacity in the NERC portion of Mexico is either oil or geothermal.

Figure 14 shows that in the United States in 1987 coal-fired capacity is projected to provide about 54.8% of utility generated electrical energy. Coal is expected to retain its more than 50% share of annual electrical energy production in the United States through 1996. Hydro will be the mainstay of electrical energy production in Canada over the 1987-1996 period. The domination by geothermal generation in the NERC portion of Mexico is also depicted in Figure 14. The effects of energy produced by non-utility generation on fuel usage is not included in these percentages.

Electrical energy from nuclear capacity in both the United States and Canada is expected to increase over the next ten years. In the United States, electrical energy from coal, oil, and gas will decrease on a percentage basis but will increase slightly in absolute value over the forecast period. Over the same period, coal, gas, and oil for electrical energy production in Canada will increase on both a percentage and absolute basis.

Figure 14

Electrical Energy Production[a] by Fuel Type



[a] From primary energy sources (pumped storage generation and net imports excluded).

[b] Includes only that part of the Comision Federal de Electricidad system in the northern portion of Baja California, Mexico, which is interconnected with the U.S. systems.

Table 6 — Construction Status of Generating Unit Additions (1987—1996)

	NERC—U.S.			NERC—Canada		
	Number of Units	Thousands of MW	% of Total MW	Number of Units	Thousands of MW	% of Total MW
Nuclear[a]						
Not yet under construction[b]	0	0.0	0.0	0	0.0	0.0
Under construction (<50%)	0	0.0	0.0	2	1.8	40.4
Under construction (>50%)	23	25.3	100	3	2.6	59.6
Total Nuclear	23	25.3	100	5	4.4	100
Coal						
Not yet under construction[b]	25	8.1	35.8	8	2.2	66.0
Under construction (<50%)	12	8.2	36.2	3	1.1	34.0
Under construction (>50%)	11	6.4	28.0	0	0.0	0.0
Total Coal	48	22.7	100	11	3.3	100
Hydro[c]						
Not yet under construction[b]	85	2.0	79.8	14	2.5	53.6
Under construction (<50%)	18	0.3	11.4	14	2.2	46.4
Under construction (>50%)	9	0.2	8.8	0	0.0	0.0
Total Hydro	112	2.5	100	28	4.7	100
Other (Utility)						
Not yet under construction[b]	145	15.7	90.0	5	0.5	91.5
Under construction (<50%)	16	1.5	8.9	0	0.0	0.0
Under construction (>50%)	6	0.1	1.1	1	0.0	8.5
Total Other	167	17.3	100	6	0.5	100
Non-Utility Generation						
Not yet under construction	—	9.6	84.0	—	0.2	100.0
Under construction (<50%)	—	1.5	13.0	—	0.2	0.0
Under construction (>50%)	—	0.4	3.0	—	0.0	0.0
Total Non-Utility	—[d]	11.5	100	—[d]	0.2	100
Total (All Units)						
Not yet under construction	—	35.4	44.6	—	5.4	41.2
Under construction (<50%)	—	11.5	14.5	—	5.1	38.7
Under construction (>50%)	—	32.4	40.9	—	2.6	20.1
Total (All Units)	—[d]	79.3	100	—[d]	13.1	100

[a]Perry 2, WNP1, and WNP3 are in some stage of construction but are not included in these totals.

[b]Includes utility units planned but not utility authorized, units with regulatory approval pending, and units with regulatory approval received but not yet under construction.

[c]Does not include pumped storage.

[d]Non-utility generation additions are not available by unit.

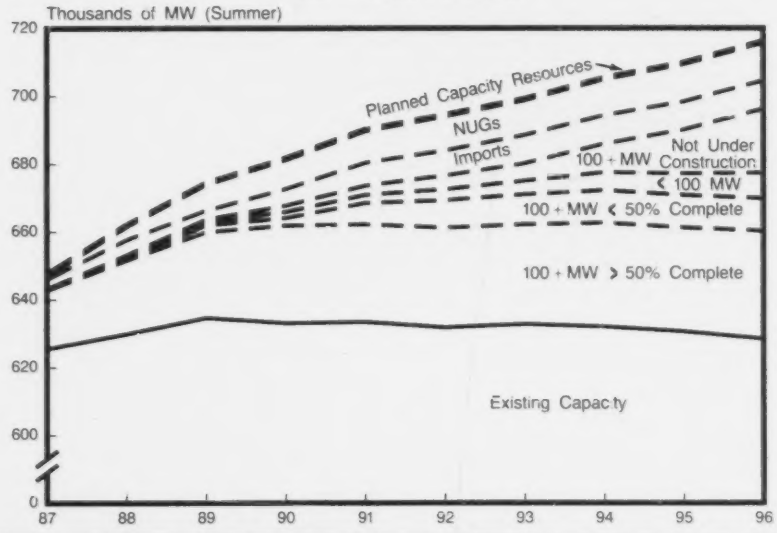
Generating Unit Construction

Table 6 indicates the current construction status of the planned generating unit additions in the United States and Canada over the 1987-1996 period. All planned nuclear units for this period are in some stage of construction and the majority of them are over 50% complete. Table 6 also indicates that of the planned coal units, 64% in the United States and 34% in Canada are in some phase of construction. Only 20% of U.S. and 46% of Canadian planned hydro additions are under construction. Similar data are shown for other utility-owned and non-utility planned capacity additions. A substantial portion of these other utility-owned and non-utility additions are not yet under construction. In total, about 45% of U.S. and about 41% of Canadian generating capacity additions which are needed to meet the requirements of electric utility customers by 1996 are not yet under construction.

Figures 15 and 16 indicate the contributions of the planned unit additions over time to the total planned capacity resources in the United States and Canada, including reliance on capacity imports. These figures in addition to depicting the construction status of the units also show that a significant portion of the planned unit additions are comprised of units of 100 MW or larger. Further, about one-third of the units 100 MW or larger are not yet under construction. Figures 17 and 18 provide further detail on those units 100 MW or larger in the United States (24,950 MW) and Canada (4,530 MW), respectively, that are not yet under construction. About 9,800 MW of the capacity additions not yet under construction are coal-fired steam units of 100 MW or larger with projected in-service dates allowing only 5 to 9 years for construction. Since it typically requires 8 to 10 years

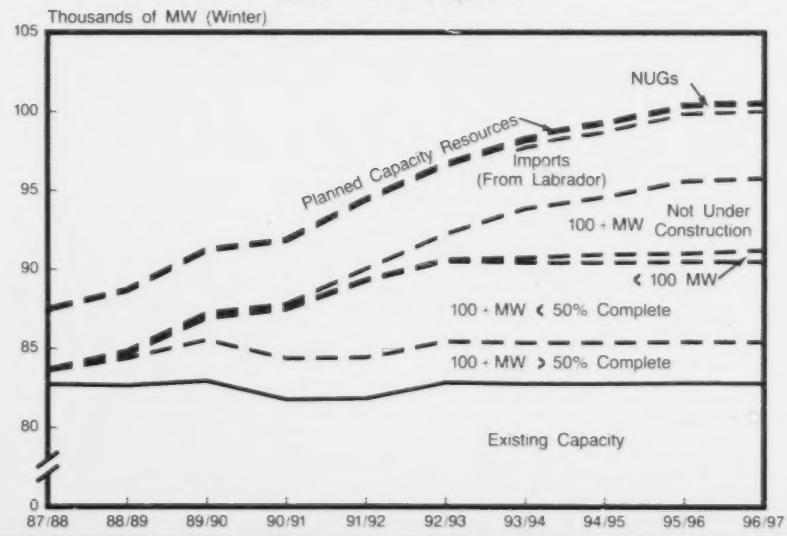
NERC—U.S. Figure 15

Planned Capacity Resources by Construction Status
1987—1996 Forecast



NERC—Canada Figure 16

Planned Capacity Resources by Construction Status
1987—1996 Forecast



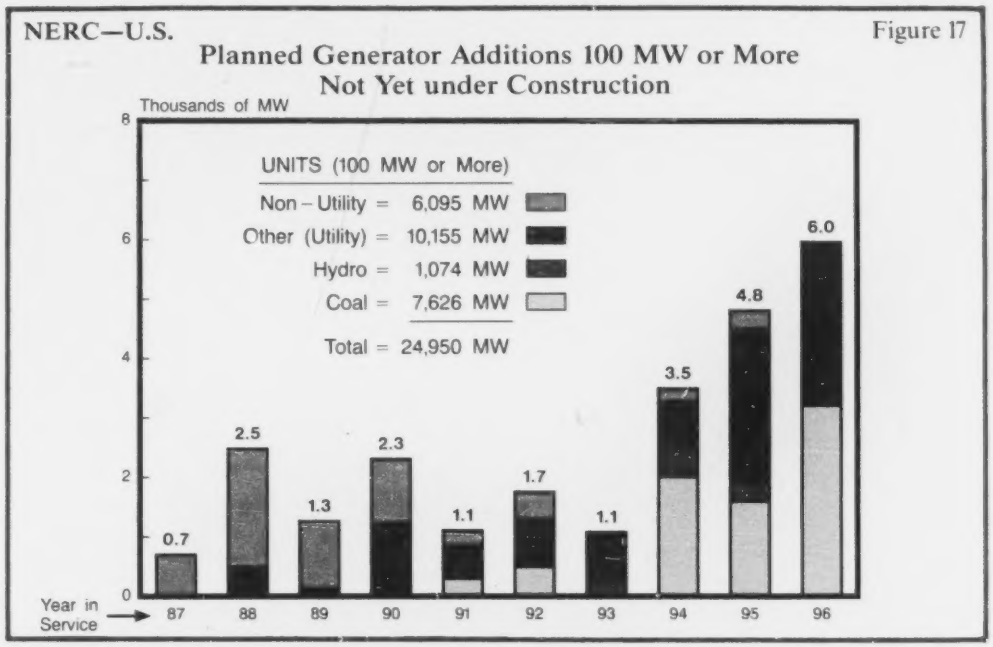
to license and build large coal units, it seems likely that much of this new coal-fired capacity will either be completed late or replaced with shorter lead time generator types.

Non-Utility Generation

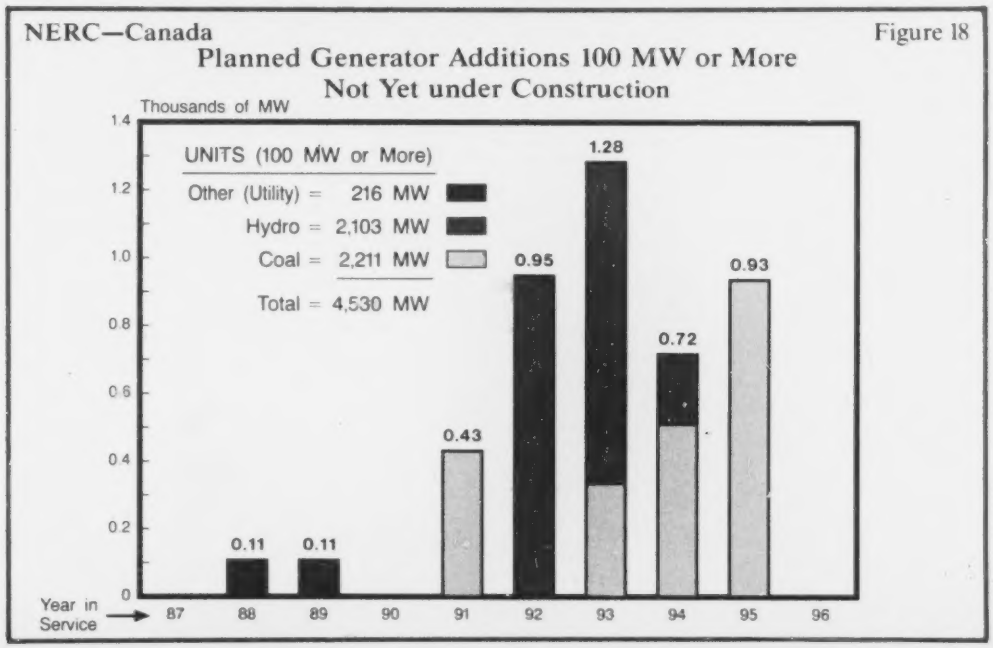
As shown in Tables 5 and 6, the NERC utilities have reported to DOE in their IE-411 reports that they expect non-utility generator (NUG) additions of about 11,700 MW over the 1987-1996 period. A breakdown of these NUG additions by fuel type is shown in Table 7. Natural gas is the predominant fuel of those NUGs whose fuel has been identified.

A recent NERC survey of the nine Regional Reliability Councils showed that all regions of NERC have some level of NUG activity. The survey also indicated that

NERC—U.S. Figure 17



NERC—Canada Figure 18



Non-Utility Generators

An April 1987 reference document, "Reliability Considerations for Integrating Non-Utility Generating Facilities with the Bulk Electric Systems" is available from the North American Electric Reliability Council. That document defines non-utility generators as facilities for generating electricity which are not owned exclusively by an electric utility and which operate connected to an electric utility system. Included are qualifying cogeneration and small power production facilities under the Public Utility Regulatory Policies Act (PURPA) of 1978, pre-PURPA non-utility owned generators, customer owned generators not covered by PURPA, and industrial or other independently owned generators which operate connected to an electric utility system.

In this 1987 Reliability Assessment report, the data on non-utility generators (NUGs) is limited to only those non-utility generators which sell or are projected to sell electric energy or capacity, or both, to electric utilities. Data on industrial or other independently owned generators which generate electricity for their own consumption are generally excluded from this report.

Table 8 — 1987 NERC Survey of Existing and Planned Non-Utility Generation[a] Facilities By Summer 1996

Region	Total Projections MW	% of Total Capacity Resources
ECAR	2,653	2.6
ERCOT	2,475	4.2
MAAC	3,312	6.2
MAIN	892	1.8
MAPP	118	0.3
NPCC	3,380	2.6
SERC	3,319	2.1
SPP	654	1.0
WSCC	8,496	5.5
NERC Total	25,299	3.1
NERC-U.S.	24,707	3.5
NERC-Canada	592	0.6
NERC-Mexico[b]	0	0.0

[a]Includes NUGs treated as reductions to load, as generating unit additions, and as capacity imports.

[b]Includes only that part of the Comision Federal de Electricidad system in the northern portion of Baja California, Mexico, which is interconnected with the U.S. systems.

utilities consider non-utility generation generally in three different ways—as a reduction in load, as a generating unit addition, or as a capacity import. Table 8 shows that these three NUG categories are projected by the summer of 1996 to total approximately 25,300 MW, or about 3.1% of NERC's 1996 total planned capacity resources. Approximately 10,800 MW of the 25,300 MW are planned to be in service by the end of 1987, representing about 1.5% of NERC's 1987 capacity resources.

Table 7
NERC Non-Utility Generation Additions[a] by Fuel Type

Fuel Type	1987-1996 MW	% of Total
Natural Gas	2,834	24.2
Hydro	531	4.5
Coal	1,002	8.6
Geothermal	308	2.6
Wind	129	1.1
Solar	222	1.9
Refuse (Solid Waste)	65	0.6
Wood/Wood Wastes	39	0.3
Other or Unknown	6,587	56.2
Total	11,717	100

[a]Includes only NUGs identified as capacity unit additions. Excludes NUGs treated as reductions to load or as capacity imports.

Comparison of Recent Projections

Because of the many generation additions and cancellations, the rescheduling of unit service dates, and planned generation retirements and deferrals, it is rather difficult to compare 10-year projections of generation capacity additions from year to year. Tables 9 and 10 attempt this comparison for NERC-U.S. and NERC-Canada, respectively.

In these tables, this year's projected total installed generating capacity for the United States for the summer of 1995 (winter of 1995/96 for Canada) is compared with last year's forecast. Table 9 indicates that this year's forecast for U.S. total installed capacity in 1995 is about 3,900 MW lower than last year's forecast for 1995. Similarly, Table 10 shows that the total installed winter capacity for Canada in 1995/96 is projected to decrease by about 300 MW from last year's forecast.

A similar comparison of the differences in the forecast peak demands indicates that the U.S. 1995 summer peak demand is down by about 10,000 MW from last year's projection while in Canada the 1995/96 winter peak de-

Table 9 — Installed Generating Capacity — 1995 Summer — NERC–U.S.
Comparison of Forecasts

Total Installed Capacity	This Year's Forecast For 1995 (Thousands MW)	This Year's Forecast % of Total	Last Year's Forecast For 1995 (Thousands MW)	Last Year's Forecast % of Total	Change in Forecast For 1995 (Thousands MW)
Coal	305.6	43.6	309.4	43.9	-3.8
Nuclear	106.3	15.1	107.2	15.2	-0.9
Hydro	70.4	10.0	70.0	9.9	0.4
Oil/Gas	184.2	26.3	183.4	26.0	0.8
Pumped Storage	17.5	2.5	17.5	2.5	0.0
Other[a]	17.4	2.5	17.8	2.5	-0.4
Total	701.4	100	705.3	100	-3.9

[a]Utility and non-utility generating capacity.

mand is up by about 880 MW over last year's projection. The associated NERC-U.S. summer capacity margin for 1995 is 21.3% for this year's forecast and 20.4% for last year's forecast. Similarly, NERC-Canada's 1995/96 winter capacity margin is 19.1% based on this year's forecast and 19.3% based on last year's forecast.

The U.S. reductions in planned capacity for 1995 occur primarily in coal, nuclear, and other (utility and non-utility) generation. In addition to the differences in installed capacity due to unit reratings and planned retirements, some 4,900 MW of U.S. coal-fired units which appeared in last year's projections were removed from this year's generating unit projections, and about 1,900 MW of new coal-fired units were added to this year's projections. In the case of U.S. nuclear capacity, the major changes are the planned retirements of Ft. St. Vrain 1 in 1991 and Hanford 1 and 2 in 1993. The expected increase in U.S. hydro capacity is offset by the decrease in other (utility and non-utility) generating capacity. Oil- and gas-fired capacity in the U.S. is expected to be only slightly higher in 1995 compared to last year's forecast.

In Canada, the reductions in planned capacity for 1995/96 in hydro and oil/gas units are somewhat offset by increases in the coal-fired capacity. One new 335 MW pulverized coal unit was added to Canada's coal-fired capacity by the winter of 1995/96 compared to last year's list.

Capacity Uncertainty

All future plans are subject to uncertainty, and plans for electric generation capacity are no exception. New utility units are subject to delays due to licensing, regulatory,

Table 10 — Installed Generating Capacity — 1995/96 Winter — NERC–Canada
Comparison of Forecasts

Total Installed Capacity	This Year's Forecast For 1995/96 (Thousands MW)	This Year's Forecast % of Total	Last Year's Forecast For 1995/96 (Thousands MW)	Last Year's Forecast % of Total	Change in Forecast For 1995/96 (Thousands MW)
Coal	21.6	22.5	20.9	21.8	0.7
Nuclear	15.5	16.2	15.4	16.0	0.1
Hydro	50.0	52.2	50.7	52.7	-0.7
Oil/Gas	8.5	8.9	8.9	9.3	-0.4
Pumped Storage	0.0	0.0	0.0	0.0	0.0
Other[a]	0.2	0.2	0.2	0.2	0.0
Total	95.8	100	96.1	100	-0.3

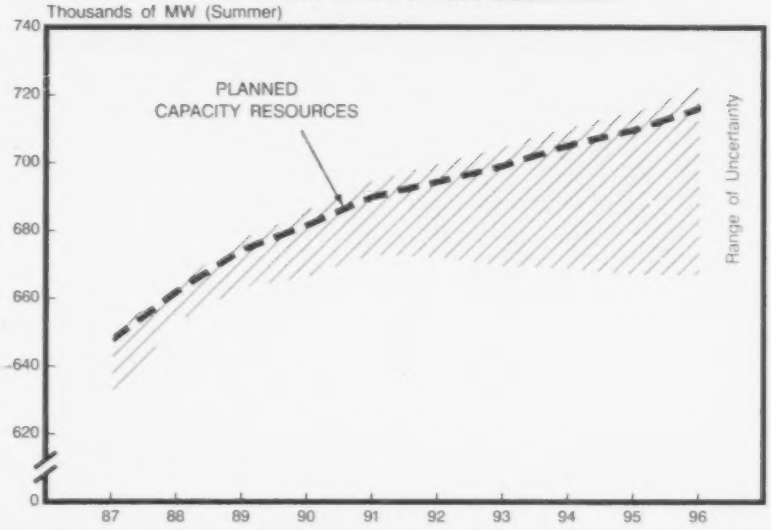
[a]Utility and non-utility generating capacity.

and public intervenor delays, as well as to delays resulting from the complexities of getting any large project completed. Non-utility generation is subject to variance from forecast as a consequence of the economic climate and, in some cases, tax incentives. However, non-utility generation, not being subject to the same regulatory constraints as utility generation, can generally be brought into service more quickly than similar utility-owned units and can also, in some cases, come into service regardless of utility need. On the other hand, economic conditions could also cause a significant amount of non-utility generation to not materialize.

The future availability of existing utility capacity is also subject to uncertainty. For example, in addition to planned retirements, reratings, and the return of some

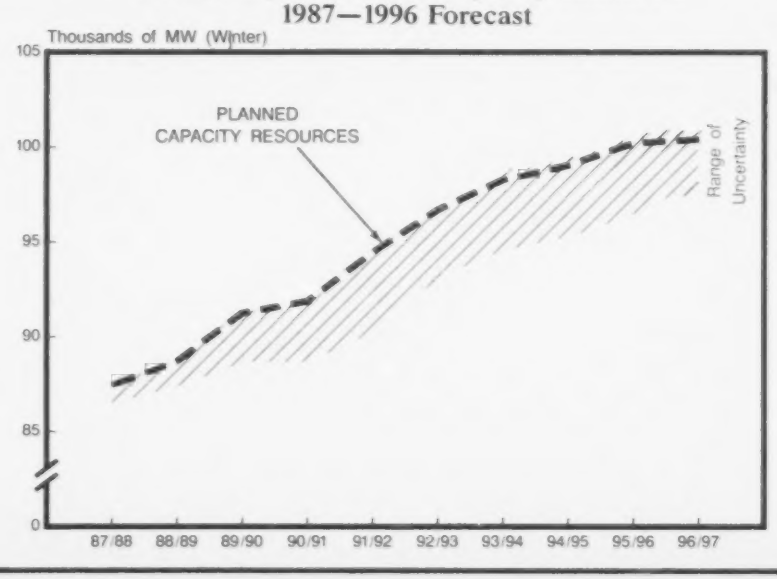
NERC—U.S. Figure 19

Uncertainty of Planned Capacity Resources
1987—1996 Forecast



NERC—Canada Figure 20

Uncertainty of Planned Capacity Resources
1987—1996 Forecast



presently idle capacity to service, the total amount of today's capacity will likely decrease as that capacity ages. As indicated in Figures 11 and 12, about 13% of the existing U.S. coal capacity (5% in Canada) will be over 40 years old by the end of the forecast period. Similarly, about 15% of the current U.S. oil- and gas-fired capacity (9% in Canada) will be over 40 years old. The extent to which older capacity will still be available for service is dependent upon economic viability and the success of generating plant refurbishment efforts currently underway at many utilities. In addition, future environmental legislation and regulations could result in some reduction in unit output of existing capacity as well as the shutdown of some existing capacity where increased environmental requirements cannot be economically attained.

NERC's base projections of capacity resources for the United States and Canada, as shown in Figures 15 and 16, respectively, assume all projected new capacity additions are completed as planned as well as the continued service of existing capacity except for planned retirements.

In an attempt to quantify the uncertainties that exist in the realization of the capacity supply plans, scenarios were postulated to determine the effects of likely events, both for planned and existing capacity, on total planned capacity resources. These scenarios resulted in ranges of the total planned capacity resources, as shown in Figures 19 and 20 for the United States and Canada, respectively.

- The higher capacity resources bound results from the following assumptions:
  - —all planned capacity additions are placed in service as scheduled
  - —no existing capacity is removed from service except for planned retirements
  - —50% more NUG capacity comes into service than anticipated.
- The lower capacity resources bound results from the following assumptions:
  - —planned capacity additions experience delays of 1, 2, or 3 years, depending, respectively, if they are currently greater than 50% complete, less than 50% complete, or not yet under construction
  - —50% of the projected NUG capacity does not come into service
  - —about 7.5% of the existing coal-fired capacity in the U.S. is removed from service due to refurbishment of some older units not being economically attractive
  - —about 5% of the coal-fired capacity installed prior to 1975 in the U.S. is lost to service as a consequence of future environmental regulations. An adjustment has also been made to Canada's capacity to reflect the effects of Ontario's acid rain regulations on Ontario Hydro's capacity.

The capacity resources bandwidths of Figures 19 and 20 are inherently asymmetrical since non-utility generation may be built well ahead of forecast need while utility generation, planned to meet the projected peak demand, is not likely to be accelerated but only delayed. From Figure 19, it can be seen that the planned capacity resources by the end of the forecast period are about 716,000 MW for the U.S. with a high bound of 722,000 MW and a lower bound of about 666,000 MW or a variation of plus 0.8% and minus 7% from the base capacity resources projections. In Canada (Figure 20), planned resources by the end of the forecast period are 100,000 MW which is also the high bound because of very small amounts of NUG capacity. The lower bound is about 98,200 MW or about 1.8% less than projected. These scenario bandwidths of variation in planned capacity resources are compared with peak demand forecast probability bandwidths in the next chapter to assess future electric supply adequacy.

Assessment of Electric Supply Adequacy

Electric utilities in the United States and Canada have planned adequate capacity resources to reliably meet their base 10-year peak demand projections. However, delays in completing new capacity, higher than expected load growth, decreased availability of existing capacity, and the uncertainties associated with load management and non-utility generation threaten the adequacy of future electric supply.

Not all utilities and regions will experience these potential problems to the same degree or at the same time. Should any one or a combination of these problems materialize in significant magnitude, it will be imperative for utilities to be able to take timely and effective actions to maintain a reliable electric supply to their customers.

Capacity Margin

To provide a reliable electric supply, all systems require generation resources to be somewhat greater than the expected peak demand. Margin is the amount by which the planned capacity resources exceed the peak demand. Capacity margin is equal to margin divided by the total planned capacity resources and is expressed as a percentage of the planned capacity resources. A suitable capacity margin is needed to provide reliability of supply by allowing for planned or forced outages of generating equipment, for equipment deratings due to various causes, and for differences between actual demands and those forecast.

The required capacity margin will not be the same for each utility or region, but will vary due to different system characteristics, such as the duration of the peak load season and the outage rates for different ages, sizes, and types of generation (hydro, coal, oil, gas, nuclear, or other). It will also vary due to the support available from other systems.

The capacity margins expected in each forecast year for the United States and Canada are shown in Figure 21. The projected capacity margins in 1987 and 1996 for each region of the United States and Canada are shown in Table 11. Although the capacity margins in all areas

Figure 21

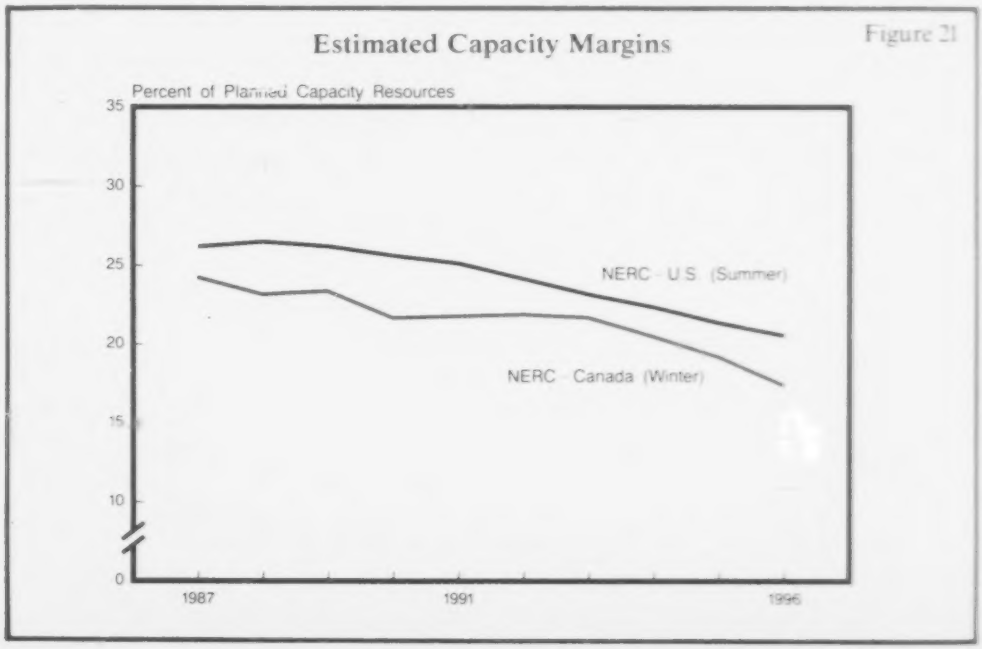


Table 11 — Estimated Regional Capacity Margins (% of Planned Capacity Resources)		
Regions (U.S.)	1987 Summer	1996 Summer
ECAR	26	21
ERCOT	20	17
MAAC	24	21
MAIN	26	18
MAAP	27	22
NPCC	24	21
SERC	24	20
SPP	29	17
WSCC	32	25
NERC U.S.	**26**	**21**
Regions (Canada)	1987/88 Winter	1996/97 Winter
MAPP	19	18
NPCC	24	18
WSCC	27	14
NERC Canada	**24**	**17**

are decreasing over the forecast period, adequate capacity resources are planned through 1996 to meet projected demands.

As NERC-Mexico has been unable to provide detailed capacity plans for the forecast period, this chapter will not assess electric supply reliability in that portion of the Comision Federal de Electricidad system in the northern portion of Baja California, Mexico, which is interconnected with the U.S. systems.

The lower capacity margins projected by 1996 will result in less flexibility for utilities to meet situations that are more severe than those expected. One result will be reduced opportunities for individual utilities to purchase capacity from neighboring systems. This could increase the likelihood of load curtailments should a temporary capacity shortage develop in an area. Occurrence in significant magnitude of any one or combination of the following developments could lead to capacity shortages:

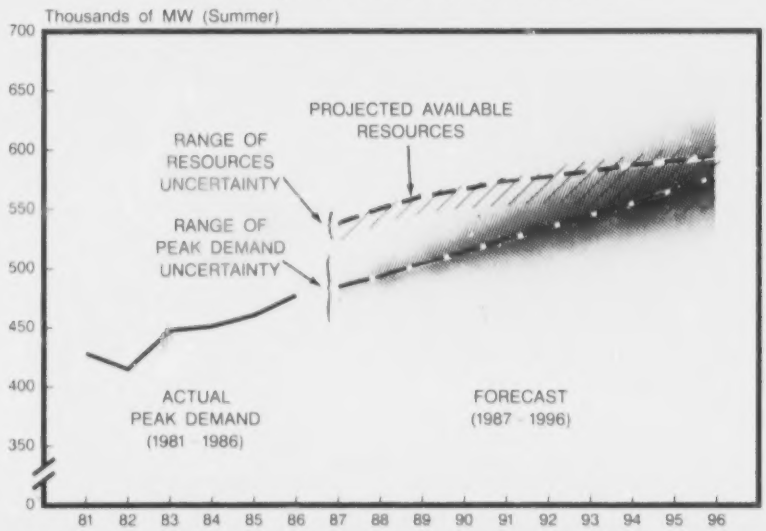
- Planned capacity additions are not completed on schedule
- Acid rain or other environmental legislation forces unit shutdowns or deratings
- Additional nuclear concerns result in unit deratings or delays in full operation
- Large blocks of non-utility generation are either not completed or prematurely cease operation due to economic factors or government policy
- Load growth is higher than forecast

Comparison of Peak Demand and Available Resources

In the chapter titled "Peak Demand and Energy," a method of showing the uncertainty of the peak demand

NERC—U.S. Figure 22

Ranges of Uncertainty for Peak Demand and Projected Available Resources



forecast was expressed as a probability band around a base forecast. In planning for capacity sufficient to supply the forecast peak demand, uncertainty also exists as to whether the capacity plans will actually reach fruition—and on schedule. The chapter titled "Generating Capacity" developed a scenario bandwidth range of uncertainty associated with the total planned capacity resources. The following paragraphs discuss how the uncertainties of the capacity resources and the peak demand forecasts can be compared to present a range of possible electric supply adequacy assessments.

Recent actual and projected peak demands are shown in Figures 22 and 23 for the United States and Canada, respectively. The base peak demand projections indicated by the heavy dashed line are considered to be the most likely for expected future conditions. The range of uncertainty regarding future peak demands is also indicated on each of these diagrams and is the same as shown in Figure 8 (U.S.) and Figure 10 (Canada) in the chapter titled "Peak Demand and Energy."

The line labeled "Projected Available Resources" provides an indication of the capacity that can be expected to be available to supply the peak demand if the planned capacity resources are installed on schedule. However, as not all installed capacity will be available at the time of peak demand, the planned capacity resources line (indicated in Figures 19 and 20 of the preceding chapter) has been adjusted based on historical generator availability data from the NERC Generating Availability Data System (GADS) and from other sources. For the United States, the projected available resources line reflects that an average of about 17% of the planned capacity resources is not expected to be available to supply the peak demand. For Canada, the corresponding amount is about 10%, reflecting a greater proportion of hydro generating capacity which has an inherently higher average availability.

Figures 22 and 23 compare the projected available capacity resources with the forecast peak demands for the United States and Canada, respectively. These figures show that the available resources, as planned, are adequate to supply the base peak demands in both the United States and Canada throughout the next decade. However, the risk of a capacity shortfall does exist.

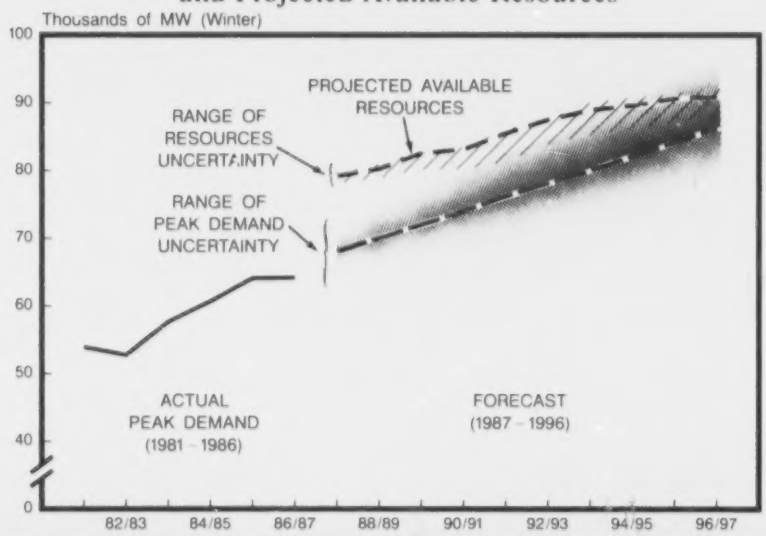
There is a 50% chance that actual demand will exceed the base peak demand projections, and a 10% chance of actual demand exceeding the upper demand bound. Should the latter occur, demand could exceed projected available resources in 1991 in the United States and one year earlier if the lower bound of resource availability were also to occur. Similarly, demand could exceed projected available resources in Canada in the winter of 1994/95 and as much as three years earlier if the lower bound of resource availability were to occur.

It should also be noted that the peak demands and their associated ranges of uncertainty include weather effects on a statistical basis, averaged over time. Weather ex-

NERC—Canada

Figure 23

Ranges of Uncertainty for Peak Demand and Projected Available Resources



tremes (hot summers in the United States or severe winters in Canada) could cause demand to exceed available capacity earlier than would otherwise be expected.

Effects of Uncertainties

Because uncertainties are associated with both the forecast peak demand and the projected available resources, two basic situations have the possibility of occurring:

- Available resources are less than demand.
  This can occur because of delays in new capacity, reductions in existing capacity, electricity demand increases faster than forecast, or a combination of these factors. This situation would continue to exist with decreased supply reliability until necessary steps can be taken to increase available capacity. The recourses when such a situation has been identified are to purchase capacity, if available, from neighboring systems or non-utility generators, install additional short lead time capacity, and increase the size and use of load management programs. Actual capacity shortfall would only occur if such recourses were not fully successful.

  A major operational impact of an inadequate supply of capacity resources is the postponement of existing generator unit maintenance. Postponed maintenance, which may be acceptable on a well-maintained system for short periods of time, will have a negative impact on reliability if continued for long periods. In addition, a major risk results if a number of neighboring systems should adopt the same practice at the same time. Further, older generating units will be called on to move from peaking duty to regulating or even baseload duty should new generating facilities be delayed. This will increase maintenance requirements on the older units which, coupled with a possible shortage of spare parts, will result in more outage time. The increased frequency and duration of older generator unit outages will also make maintenance scheduling more complex.

- Resources are available earlier than required.
  This can occur because of peak demand developing at a rate lower than forecast or if non-utility generating capacity is placed in service at a rate greater than the need indicated by the forecast load growth. In these cases, reliability is usually increased, but may be decreased if non-utility generating capacity is placed in service before necessary transmission can be built. Reliability can also be indirectly improved if the additional capacity or lower than forecast load results in greater flexibility in generator maintenance schedules and capacity sales.

These uncertainties have made development and realization of long-term capacity plans even more challenging than in the past. The electric utilities have a commendable history of being able to match load and resources, even though using extraordinary measures in some instances or temporarily living with reduced reliability.

If a trend toward higher growth should begin, prompt recognition of the trend will be essential to initiate an adequate response. Since one or two years of higher-than-forecast peak demands may be caused by temporary conditions, several years may be required to identify a new trend in the peak demand growth rate. Once an increase in growth rate is identified, it may be too late to install baseload generation in time, as typical baseload capacity lead times are 8 to 10 years. Utilities may be limited to short lead time generation options to provide adequate capacity, and even these require about three years lead time.

Reliance upon short lead time options by many utilities could cause a situation where many orders for such equipment would require delivery at approximately the same time. This could exceed the capabilities of the equipment manufacturers to produce this needed equipment and result in several of the utilities seeking to rely on the resources of their neighbors. The neighbors, in turn, may be in the same situation and may not be in a position to provide sufficient assistance. Reliance on load management would provide only minimal relief. Based on a recent NERC survey, the effect of the projected load management programs on the potential capacity shortfalls indicated in Figures 22 and 23 would be to delay capacity needs by no more than one year in either the United States or Canada.

It should be noted that the projections included in Figures 22 and 23 apply to the composite peak demand and capacity resources of the United States and Canada and therefore cannot be inferred to reflect the situation in any Regional Council, utility, or group of systems in either country. Some regions or utilities may experience critical capacity situations earlier than these national figures would indicate.

Load Management

Load management is a tool that is being used by many utilities to reduce peak demand and thus delay generating capacity additions. A NERC survey indicated that the equivalent of about 3% of the peak demand in both the United States and Canada will be under load management by 1996.

The benefits of load management to a utility and the amount of customer load that can be reliably and cost-effectively managed tend to be unique to each utility sys-

tem. Some of the factors which significantly influence the benefits of load management are:

- the variation of the customer's peak demand with time on a daily, weekly, seasonal and annual basis
- the overall characteristics of utility system peak demand and resources
- the margin of a utility's capacity resources over its peak demand
- the timing and cost of new capacity resources and of implementation of the load management programs
- the costs and availability of competing fuels for electric generation.

There are also certain drawbacks and uncertainties associated with dependence upon load management as a tool to delay capacity additions. A key uncertainty is customer acceptance. Utility experiments and pilot programs have so far led to conflicting evidence. In some systems, customer acceptance has been good, while in others it has been more negative. The danger is that customers who initially participate in load management programs because of the financial incentives may decide, once the electric supply to their equipment has actually been interrupted a number of times, that the inconvenience of these interruptions outweighs the cost savings and withdraw from the programs. Such actions, particularly if taken by commercial and industrial customers, could result in large increases in utility peak demand which must be served at a time when capacity supply may already be critical.

Another factor, often overlooked, is that load management will not always and everywhere be cost effective. The financial incentives used in most experimental and pilot programs are relatively modest. If utilities find that incentives must be increased to discourage or offset customer withdrawals, a program which was initially cost effective could quickly become one that is not.

Load management will be most attractive on utility systems which have very pronounced peak demands. The higher a utility's load factor (the less pronounced its peaks), the less effective load management will be. Load management could also decrease the load diversity in power pools, requiring larger capacity margins for the individual members. For example, the Mid-Continent Area Power Pool (MAPP) requires an 18% capacity margin on a pool basis; however, because of the diversity in peak demand among the member utilities, each utility is only required to maintain a 13% capacity margin. To the extent that load management would decrease diversity, capacity requirements for the members would increase.

Load management cannot be considered as a resource on the same basis as generating capacity. Depending on the usage patterns of the managed loads, the MW value of load management may be less during off-peak periods than at peak load. A generating unit, on the other hand, can always provide the same number of megawatts. Because load management is a demand reduction rather than a generating source, it has several operating features that may tend to lower total system reliability. For example, utilities may be unwilling or unable, due to contractual or regulatory restrictions, to use load management for such things as helping a neighboring system that is short of capacity even though generating capacity would be used for that purpose.

More important, there is substantial uncertainty as to how much actual load reduction will be realized at a particular time on any given day when it is needed. As a result, individual systems may have less on-line capacity than required and the reliability of the interconnected systems would suffer. Inconsistent load response has already been observed in experimental and pilot load management programs. Some influencing factors are time of day or season, and the fact that many industrial and agricultural subscribers insist on the capability to override the utility load management interruptions.

Load management has many potential advantages, but it also has many potential drawbacks. The relative weight of both is still uncertain.

Capacity Construction Plans

In Canada, 4,360 MW of nuclear capacity, 1,140 MW of coal-fired capacity, and 2,180 MW of hydro capacity presently planned for service over the next 10 years are already under construction. Another 5,400 MW or 41% of the total planned capacity additions for Canada are not yet under construction. However, the expectation is very high that all or most of this capacity will come into service on schedule.

The situation in the United States for units under construction is less favorable than Canada's situation. Of the 10,870 MW of U.S. nuclear capacity scheduled for commercial operation in last year's projections during April to December 1986, only 3 units (totaling 3,360 MW) were placed in service. For the 1987-1996 period, U.S. utilities indicate that there are 23 nuclear units totaling 25,300 MW of capacity under construction in the United States, all of which are more than 50% complete, and planned for service over the next 10 years. One of these scheduled units, Harris 1, a 900 MW nuclear unit, has gone into full commercial operation in early 1987. Since last year's review, the service dates of 11 nuclear units remain unchanged while 10 units have been delayed an average of 12 months, and only 1 unit was advanced by 3 months. In view of continuing difficulties in satisfying all regula-

tory requirements to obtain operating licenses, the service dates of all 22 nuclear units must be considered at risk.

Non-Utility Generators

Due to PURPA and the current economic and political environment, rapid growth of non-utility generation has occurred. This growth in NUG capacity has, in many aspects, benefited both utilities and utility customers. However, it has also prompted a growth in reliability related concerns.

The NUG-related concerns include issues such as:

- Reactive power support and voltage control
- Supply planning uncertainty
- Siting considerations
- Transmission loading problems
- Lead time for new facilities
- Unit performance statistics
- Capacity forecasting complications
- Rapid operational mode changes
- Backup capacity requirements
- Integration into utility operations

Reactive power is often overlooked, yet is a critical technical issue. In addition to supplying megawatts of real power to provide energy for customers' needs, a utility must also produce reactive power, measured in megavars, to supply the needs of devices used by customers, and to maintain the voltage necessary for the electric system to function properly. Both static and dynamic reactive power sources are required to maintain transmission network voltage levels during normal and emergency conditions. Many NUGs provide significantly less reactive support to the networks than the utility generation they may displace and they can produce voltage problems if not dispatched in combination with the utilities' own generation. For example, induction generators used by many small power producers actually draw reactive power from the system, rather than supply it. Utilities with significant amounts of NUG capacity are often forced to provide supplemental static and dynamic reactive supply systems to maintain system reliability and to avoid sudden system voltage collapse. There are few incentives for NUGs to supply reactive power themselves. This concern is most critical in those regions where enough NUG capacity is available to significantly reduce the amount of utility-owned generation on-line.

NUGs add uncertainties which reduce the ability of utilities to conduct supply planning with confidence. Those uncertainties include issues such as fuel supply availability, future economic viability and therefore longevity of the NUGs, and enforceability of long-term NUG supply contracts.

Reactive Power

While many people are familiar with electrical terms like "volts," "amps" and "watts," few have heard of the term "reactive power." Yet, reactive power, often referred to as "vars" or "volt-ampere reactive," is required by many devices used by utility customers and is essential in the transfer of electricity from the point of generation through the transmission and distribution systems to the customer.

Reactive power is analogous to the more familiar active or real power, which is measured in watts. While active power is the means by which ac energy is supplied to perform useful work like running a motor or lighting an electric bulb, reactive power provides the important function of maintaining voltage—and if an adequate voltage level is not maintained, active power or watts cannot be supplied. Reactive power thus provides the means by which watts can be transmitted to do useful work.

A useful analogy might be made with dye used to color fabric. Real power can be compared to the pigment or tint; reactive power would then be the water with which the dye is mixed. The water doesn't color the fabric, but without it the pigment would not be able to do its job.

Reactive power can be produced by generators and capacitors and by certain specialized devices such as synchronous condensers. In order to operate, reactive power is required by many customer loads—such as large industrial machinery and the motors in refrigerators, air conditioners, etc. It is also consumed in transmitting electricity through transmission lines and transformers, just as real power is consumed in transmission losses. However, in virtually all transmission lines and transformers, reactive power losses greatly exceed the active or real power losses. Consequently, unlike active or real power, reactive power cannot be transmitted over long distances. As a result, reactive power must, to a large degree, be provided close to the point of use.

The siting of NUGs may also present reliability problems. If siting results in a concentration of NUG capacity in a small area without sufficient transmission reinforcement, load-generation imbalance problems may be created and stability margins may be reduced. In addition, in some cases higher system short circuit levels may require replacement of utility as well as nearby customer equipment.

The short construction lead times of most NUG facilities are beneficial when utilities are faced with short-term capacity shortfalls. However, the short construction lead times can create system problems when NUGs are located in areas with sufficient utility generation supply. The transmission system may not have the capability to export excess generation from the area. The long lead times experienced by many utilities for transmission construction have, in some cases, led to restrictions on both NUG and utility generation until the transmission system constraints could be eliminated. Such situations have been experienced along the Texas Gulf Coast and in California.

Availability and performance of NUG facilities are important reliability considerations. Due to the smaller individual unit sizes, typical of most NUGs, traditional reliability indices such as loss of load probability may be improved if some amount of non-utility generation is included in a system. However, if the availability of NUG facilities is less than that of utility generation, net reliability could be reduced. Currently, most NUGs do not have enough operating experience to establish a statistically accurate unit availability data base.

Forecasting of future capacity requirements by utilities has been greatly complicated by the rapid development pattern of NUG capacity in some regions. Traditional load growth patterns permit utilities to plan five to ten years or more in the future. Often, this lead time is necessary to accommodate regulatory and certification processes. On the other hand, since the regulatory and certification process is less stringent for NUGs, significant amounts of NUG capacity can be placed on-line in a much shorter time. As a result, the capacity requirement of the utility can change quickly. Increased uncertainty in forecasting capacity requirements results in reluctance to commit significant financial resources for additional needed capacity.

In some areas, NUG capacity and energy can be sold to the connecting utility, other utilities, or used to serve its own local load. Changes from one of these modes to another could occur on an hour-to-hour basis. This can cause rapid short-term swings in daily load patterns which can complicate utility generator unit dispatch considerations and adversely impact operational reliability. Unless carefully monitored, such transactions may also distort historical load data and mask important trends.

Provisions are included in PURPA which require utilities to provide backup or standby capacity to qualifying facilities. For this reason, backup capacity commitments are increasing. These backup capacity requirements are difficult to predict and properly incorporate into the load and capacity forecasts and into operations planning. A second concern regarding backup capacity is that within a specific geographical area, many NUGs use a common fuel. In most cases, this fuel is natural gas. Should dependence on the utilities' backup commitment occur as a result of a fuel disruption among the NUGs, a major drain on available utility capacity margins could result.

The present electric system was not originally designed for the integration of NUGs and therefore it may not always be able to accommodate the NUG additions without degrading system reliability. Large numbers of widely dispersed NUGs present complex communication and control problems as well as maintenance scheduling problems to integrate them into utility system operations. However, unless NUGs are properly integrated into system operations, a NUG which operates baseloaded during off-peak hours can force the shutdown of utility generators during the night or during weekend periods because of minimum load constraints on the utility generating units. Further, the utilities' larger, more complex units may not be able to be restarted for the next day's peak demand due to mechanical and thermal constraints.

NERC has recently issued a reference document on non-utility generation entitled "Reliability Considerations for Integrating Non-Utility Generating Facilities with the Bulk Electric Systems" dated April 1987. If the operator of the non-utility generator recognizes the issues and adheres to the recommendations in this document, NUG operation should be compatible with utility operations.

Fuel Supplies

Throughout 1986 and early 1987, utilities have enjoyed abundant supplies and attractive prices for coal, natural gas, and fuel oil.

The precipitous drop in world oil prices early in 1986 resulted in a significant increase in the use of oil for electricity production, giving competition to natural gas. As usage of oil and gas has grown, so has concern over the continued reliability of supply of these fuels. As history has shown, Mideast politics, oil embargos, or controlled pricing can result in unexpected demands for and shortages of future domestic supplies.

While many utility customers are currently benefiting from savings due to depressed prices of gas and oil, the continuation of these low prices keeps drilling activities at a minimal level, causes marginal domestic wells to be shut down, and reduces existing supplies with little restoration of oil and gas reserves for the future. Continued reduced domestic exploration could increase utility dependence on foreign supplies.

Many gas customers have stopped using long-term contracts and have switched to purchasing gas from the lower cost spot market. This can have long-term effects on the stability of gas supplies. Approximately 80,700 MW of the 145,000 MW total (1986) oil-burning capacity in NERC are capable of burning either oil or natural gas. Should oil become scarce, or economically unattractive, many of these units could be switched quickly to gas, resulting in a potential strain on available supplies.

Fuel supply concerns also exist in the future use of coal in electricity production. Utilities with heavy dependence on coal-fired capacity must balance the economic cost of fuel stockpiles with the risk of fuel supply interruption. Most coal dependent utilities believe that 60- to 90-day fuel stockpiles are prudent, but economic pressures frequently force utilities to take the supply reliability risk associated with lower stockpile levels.

Many coal dependent utilities have adopted, or are considering adopting, a strategy of establishing diverse coal supplies for each coal plant not only to meet environmental requirements, but to minimize the risk of supply interruptions, and to maximize negotiating leverage with suppliers. Similarly, a mix of spot market and long-term variable demand contracts helps to provide supply pricing flexibility and fuel supply reliability. Regulatory actions, however, such as cost recovery penalties for high stockpile levels, requirements to limit out-of-state coal usage, and strict environmental regulations, tend to reduce utility coal supply flexibility and could, therefore, affect reliability adversely.

Transmission Assessment

The bulk electric transmission systems in NERC are complex, reliable interconnected networks developed through coordinated efforts among utilities. Utilities are planning additions to these transmission systems to serve customer load, to enhance energy transfer capability, and to ensure continued reliability. However, these additions are often delayed by various impediments and factors which discourage utility investment.

Portions of the transmission systems will continue to be heavily loaded by energy transfers, both within and among regions, as utilities strive to minimize the cost of electricity. In some areas, concentrations of non-utility generation will further increase loadings on already heavily utilized facilities. In addition, energy transfers among systems can increase loadings in many other systems not party to the transfers. Similarly, disturbances in one system can affect the reliability of other systems. All of these factors underscore the need for utilities to continue their ongoing efforts of coordinated planning and operation of the bulk electric transmission systems.

Delays encountered in the expansion of these transmission systems further compound the stress on the transmission networks by reducing operating margins and the flexibility of these systems to respond to facility outages and other system emergencies.

Bulk Electric Transmission Systems

The bulk transmission networks are essential components of the electric power systems. Overall reliable electric supply is rooted in the adequacy of the planned transmission networks and their day-to-day operations.

The bulk electric transmission systems in Canada and the contiguous United States are comprised of four separate major Interconnections: the Eastern Interconnection, the Western Interconnection, the Texas Interconnection, and Quebec. These Interconnections are comprised of a network of transmission facilities designed for and operated at alternating current (ac) and direct current (dc) voltages. The ac facilities operate at voltages from 230,000 volts to 765,000 volts, while the dc facilities range in voltage from ±250,000 volts to ±500,000 volts.

There were 179,161 circuit miles of ac transmission lines and 3,527 circuit miles of dc transmission lines in service in the NERC regions as of the end of 1986. An additional 18,428 miles of ac and 1,380 miles of dc transmission lines are planned for the next 10 years, bringing the total NERC bulk electric transmission systems to 197,589 circuit miles of ac and 4,907 miles of dc lines by the end of 1996.

Figures 24 and 25 compare the current 1987-1996 projections of transmission additions in the United States and Canada, respectively, to similar 10-year projections made in 1984, 1985, and 1986. Since the 1985 forecasts, the total amount of planned transmission facilities has declined both in the United States and Canada. This trend is due to cancellation or deferral of planned generation additions and their associated transmission facilities, as well as to efforts to increase the capability and use of existing facilities.

In this report, all designated transmission lines should be assumed to be alternating current (ac) lines unless otherwise specified.

Adequacy of the Transmission Systems

The bulk electric transmission systems in NERC are judged to be adequate as planned through the next 10 years to deliver projected customer electricity requirements reliably.

Continued adequacy of the bulk electric transmission systems will depend on timely completion of planned new transmission facilities in all of the regions. Cooperation of the regulators, legislators, customers, and the utilities will be required to remove impediments to the li-

Interconnections

In the one hundred-year history of the electric utility industry, utilities have grown from isolated systems supplying their customers from local resources to highly interconnected systems (or "Interconnections") of generating stations and high voltage transmission lines encompassing large geographic areas and many individual utilities. Today, in NERC, there are four major interconnected areas: the Eastern Interconnection, the Western Interconnection, the Texas Interconnection, and Quebec. The boundaries of these areas are shown in the accompanying map.

Interconnections of the North American Electric Reliability Council

Within each Interconnection, individual utility systems are connected together by alternating current (ac) and direct current (dc) transmission lines. The alternating current frequency will be the same at all points in an interconnected area. A simple manifestation of this phenomenon is that electric clocks will run at the same speed in all parts of an interconnected area. Another feature is that a disturbance occurring at any location in the interconnected area will be felt at all other points. Similarly, electricity transfers from one portion of an interconnected area to another will, to some extent, flow over all transmission lines not only those in the direct path of the transfer.

Since it is impractical to use alternating current transmission lines to tie the major Interconnections to each other, direct current facilities are used for this purpose.

censing and construction of necessary transmission facilities. In addition, as utilities continue to strive to meet customer electricity requirements at the lowest practical cost, the existing extensive coordination among utilities in planning and operating the bulk electric systems is being expanded to include even larger geographical areas to ensure that reliability is maintained.

Transmission Utilization

The bulk electric transmission systems in some areas will continue to be heavily utilized throughout the next 10 years to transfer energy from remote generating sources to load centers.

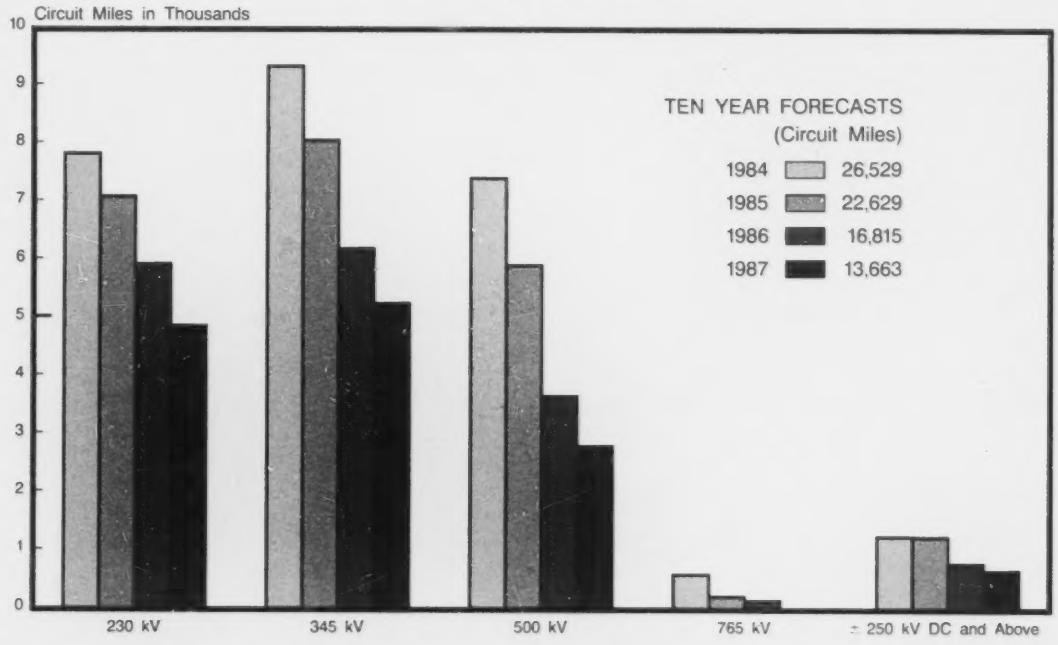
Economy energy transfers will continue among utilities both within and among regions whenever there is a sufficient incremental electricity price differential, generally due to differences in the cost of fuels used to generate electricity. The extent of such transfers will continue to vary with fuel price differentials. Hydro-generated energy in the Pacific Northwest will continue to be transferred to the Pacific Southwest. Coal-fired energy will be transferred from west to east across the Mid-Atlantic Region. Similarly, Florida systems are expected to continue to import lower cost electrical energy to displace higher cost electricity generated from oil.

In addition, some utilities have entered into long-term agreements to purchase capacity from other utilities to defer investing in new generating facilities. For example, utilities in NPCC and MAPP plan to increase imports from Canada, and utilities in MAAC and the VACAR Subregion of SERC have long-term capacity purchase agreements with utilities in ECAR.

NERC—U.S.

Figure 24

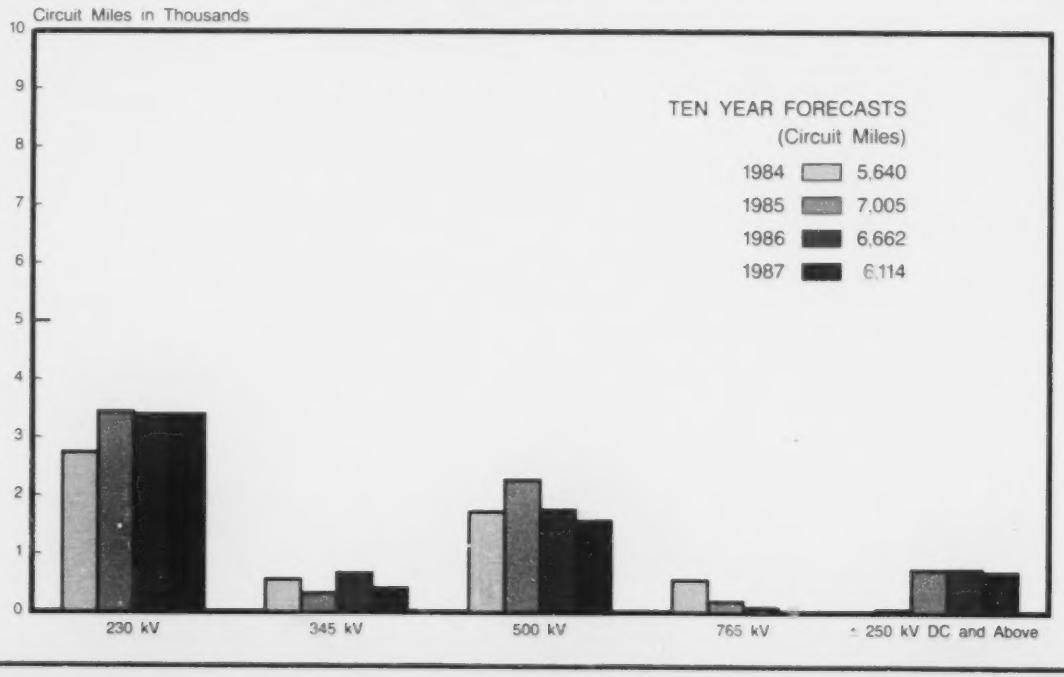
Planned Transmission Additions



NERC—Canada

Figure 25

Planned Transmission Additions



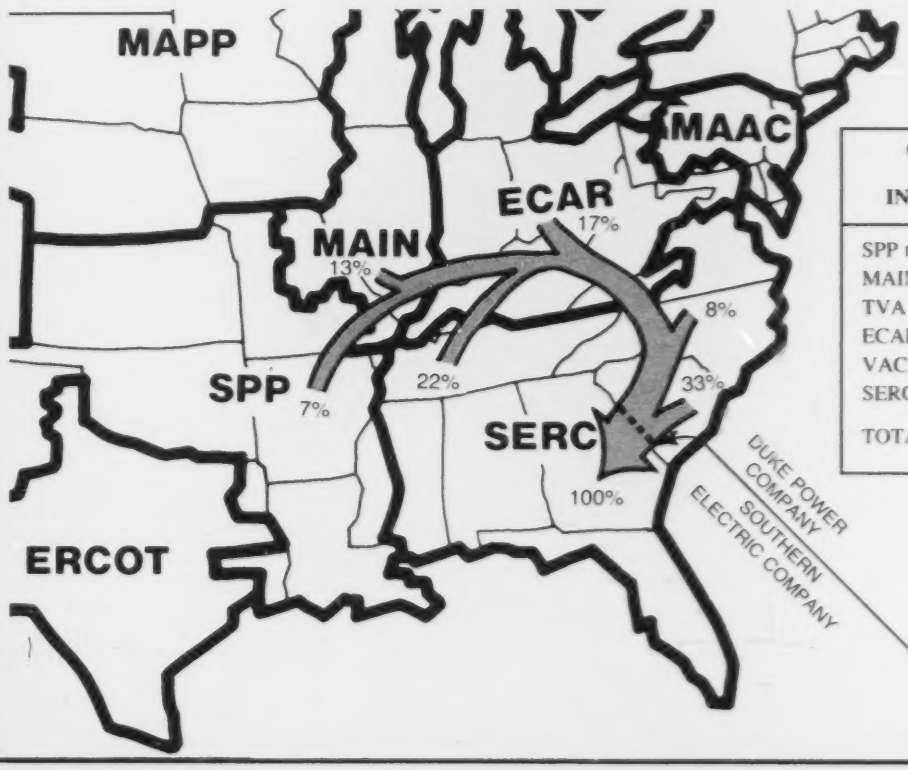
The increasing number of both economy energy transfers and capacity purchases among adjacent and non-adjacent utilities anticipated during the next 10 years will tend to increase loadings on some key transmission facilities. In many instances, certain of these facilities will be loaded at or near their capability limits much of the time. Further, in some areas, a concentration of non-utility generation will create load and generation imbalance problems which could increase loadings on already heavily loaded transmission facilities.

The Savannah River interface (transmission lines across the Savannah River) between the Southern electric system and Duke Power Company in the SERC Region is illustrative of a typical transmission system interface where sufficient interchange capability had been planned to accommodate expected normal and emergency transactions. Now, however, the interface transmission is also being affected by economy energy transfers between other adjacent and non-adjacent systems. Figure 26 demonstrates how the loading on the transmission ties connecting these two utilities is affected by significant multiple transactions among utilities other than the two interconnected parties. Such transfers of energy through parallel paths of neighboring systems, not party to the transactions, can decrease the amount of direct control operators of those neighboring systems have on their transmission loadings. This also illustrates that multiple energy transactions can create complex operating and control problems which require continuous close cooperation and coordination among systems to resolve. The effects of these transactions, and those of non-utility generation, on the loading of key transmission facilities must be continuously monitored and properly controlled to ensure reliable system operation.

Although bulk electric transmission systems are planned and operated in accordance with established regional reliability criteria, heavy transmission loadings increase exposure to voltage collapse because of increased reactive power losses and reduced operating margins. In addition, as the transmission systems are further utilized to transfer large amounts of energy over greater distances, there will be an increased exposure to system (dynamic) instability and less transmission capacity margin to survive unexpected facility outages. Voltage collapse

Figure 26

Typical Loadings on a Transmission System Interface between Two Utilities



CONTRIBUTORS TO SAVANNAH RIVER INTERFACE FLOWS (%)	
SPP to SERC	7
MAIN to SERC	13
TVA West to TVA East	22
ECAR to SERC	17
VACAR to TVA	8
SERC (Other Intraregional)	33
TOTAL	100

and instability are phenomena that occur in fractions of a second if transmission loadings exceed allowable transfer limits or if an unforeseen combination of contingencies (facility outages) occurs.

In order to mitigate the effects of heavier transmission use, static var compensators and other reactive power supply devices are being planned to allow higher transmission loadings closer to facility maximum operational loading limits.

Complex special protection systems (SPS), also known as remedial action schemes, are also being used to extend transmission system capabilities without new transmission construction. SPS use is becoming increasingly common and their number is expected to increase in the future. The SPSs are designed to shed load and/or generation automatically in order to prevent widespread interruptions of electric supply to customers if certain facilities should fail. Considered one at a time, SPSs can be economic and acceptable. However, with many of these special protection systems being installed and with the reliability of interconnected systems being dependent upon correct SPS operation, the compounding effect of these devices on reliability has become a matter of concern and will be increasingly so in the future. Nevertheless, these devices and protection schemes are being used and are planned as alternatives to new transmission.

Operations

With complex interchange effects, such as occur on the Savannah River interface, it is critical that system operators be well trained. Because the operators will be required to consider more options in the future before they make their operational decisions, operator training is being improved to include the use of new tools necessary to meet the complex challenges of the expanding electric systems. System restoration procedures also undergo frequent review and are an integral part of operator training.

Even the best trained operators will require upgraded tools with which to operate in the future. This need has been answered to a great extent by the escalation of telecommunication and digital computer facility advances that have been made available to the industry over the past several years. Utility systems have been quick to apply these new technologies to their operations and will continue to do so in the future. Future applications in the area of utility operations will probably include knowledge-based (or expert) digital computer systems as well as increased automatic data transfer within and among the regions.

Coordination

A need to exchange system information and to coordinate planning and operations among systems has been recognized since the first intersystem transmission tie was made decades ago. Since that time, information exchange and coordination have developed to the present highly sophisticated network of telecommunication facilities and coordination procedures. The reliability of today's bulk electric transmission systems is the result of such extensive cooperation and coordination. The interactions among the systems and regions will require even greater dependence on cooperation and coordination in planning and operations on both a regional and interregional basis in the future for the following reasons:

- Electrical energy transfers within a region and among regions impact loadings on transmission facilities of utilities that are not parties to either the energy transaction agreements or the associated transmission service agreements. When electrical energy is transferred from one geographic area to another, the transferred energy flows throughout the interconnected network regardless of the contractual transmission service arrangements. This change in line loading can adversely affect the reliable and economic operation of utilities not participating in the transfers. Further, the increasing number of simultaneous electrical energy interchange transactions will contribute to the complexity of the situation. Increased use of bulk transmission facilities can also reduce the flexibility to cope with unexpected bulk system outages and the scheduling of maintenance outages.
- Disturbances in one part of an Interconnection can significantly change loadings and voltages on facilities of geographically remote but electrically integrated systems. For example, when a sudden outage of a generator occurs in an Interconnection, the lost generation is instantly and automatically replaced by all remaining generators in the Interconnection. Power flows on facilities throughout the transmission network change immediately when this occurs. Similarly, when a major transmission line fails, the power that was flowing on that line is immediately and automatically redistributed to all other ac transmission lines in that Interconnection. Either event can result in a sudden increase in loading on already heavily loaded transmission facilities in areas remote from the disturbance.
- In day-to-day operations, the electric systems are never fully available. There are always generation and transmission equipment outages due to maintenance, construction, and equipment failure that leave something less than the total system in service at any time.

Intraregional and interregional coordination of all such outages will continue to be vital to ensure bulk system reliability.

Interregional Coordination

Since the first intersystem tie several decades ago, electric utilities have recognized the need to exchange information and to coordinate both system planning and operating matters in order to maintain adequate bulk electric system reliability. Today's extensive intraregional and interregional coordination among utilities is conducted using highly developed communications facilities and coordinated procedures, many of which are supported by planning and operating contracts and agreements between and among systems, groups of systems, and regions.

During the system planning process, various intraregional and interregional reliability studies of projected system conditions are performed to assess overall system reliability and to ensure that generation and transmission expansion plans are coordinated. Before new bulk electric system facilities are actually placed in service, studies are made of a wide range of possible future system operating conditions to ensure that the new facilities can be integrated into the existing bulk electric transmission networks in a reliable manner.

In the day-to-day operation of bulk electric systems, extensive intraregional and interregional coordination and data exchange continues around the clock in order to provide utility system operators with timely information that is essential in the reliable operation of the highly integrated bulk electric systems. This includes the sharing and coordination of operating plans—such as transmission and generation outage schedules and projected energy interchange transactions. It also includes the sharing and coordination of on-line information such as anticipated load patterns, generation dispatch patterns, energy interchange schedules, heavy transmission line loadings, facility outage information, and other projections of near-term changes in system operating conditions.

In public policy matters affecting electric utilities, great care must be taken to ensure that complete and free information exchange and coordination can continue among the electric utilities. Effective utility communication and coordination are critical to the future reliability of the bulk electric systems.

The severity of the effects of energy transfers or disturbances depends on many factors including the nature and size of the disturbance, the number and magnitude of simultaneous transfers taking place, and both the loading on the transmission facilities prior to the disturbance and the magnitude of the change in loadings caused by the transfer or disturbance.

The extensive and increasing cooperation and coordination among utilities on local, regional, and interregional bases must continue in order to identify remote system impacts and to develop appropriate plans and operating procedures to maintain reliability.

The following examples illustrate the scope of planning and operational coordination that exists within NERC:

- In MAPP, during off-peak load periods, utilities in the eastern and southern parts of the Region purchase economy electrical energy from the mine-mouth coal units in the west and from Canadian hydro capacity in the north. In the 1970's, when the interconnection capacity was initially developed and economy transfers became possible, the system experienced dynamic instability. A coordinated study procedure which established transfer limits and facility loading relief procedures for the system operators has since been developed by the utilities. A formal review process within MAPP is required for each planned facility addition to the network to ensure that reliability criteria will be met and transfer capacity will not be degraded. Through these procedures, MAPP has been able to maintain the stability of the network and increase economy transfer capabilities.
- In WSCC, disruption of the Pacific North-South Intertie by an outage of both 500 kV ac lines or both poles of the high voltage direct current (HVDC) line can adversely impact the eastern portion of WSCC. WSCC has placed high priority on coordinated studies to determine effects on reliability of plans to: (1) increase the transfer capability of the ac and dc components of the Pacific Intertie, (2) increase Arizona-California transfer capability, and (3) control loop flows by the installation of phase shifting transformers in southwestern Colorado. Alternative remedial action schemes are also being evaluated which would minimize the effects of disturbances on neighboring systems.
- In NPCC, Hydro-Quebec exports energy to adjacent systems in New York, New England, and New Brunswick over 5 HVDC ties. The present 2,590 MW capacity of these ties is scheduled to increase to 3,900 MW with the expansion of the Hydro-Quebec to New England Power Pool (NEPOOL) tie to 2,000 MW in 1990. Loss of either the planned 2,000 MW tie or the collapse

of the Hydro-Quebec system (resulting in loss of all HVDC ties) can adversely affect transmission systems in NPCC, MAAC, and ECAR. To mitigate the effects of the latter contingency, Hydro-Quebec has developed a dynamic isolation scheme which will maintain 2,000 MW of the total transfer on the Hydro-Quebec — NEPOOL tie in the event of the loss of the Hydro-Quebec system. A New England backup load shedding scheme is also being developed.

Because of the potential for widespread intraregional and interregional effects, numerous joint and interregional studies have been and are being conducted. Certain of these studies have resulted in implementation of coordinated procedures to mitigate the adverse effects of current Hydro-Quebec HVDC exports on the reliability of the existing systems. Other studies, both regional and interregional, are analyzing the contingencies noted above to determine if the reliability of the interconnected systems is adequately maintained. One of these, a joint MAAC-ECAR-NPCC (MEN) Study, is reviewing studies conducted by Hydro-Quebec and NEPOOL, in addition to conducting its own analyses of the dynamic performance of the 1990 system.

In parallel, NPCC is reviewing a proposal by Hydro-Quebec for changes to its transmission criteria to meet NPCC's "Basic Criteria for Design and Operation of Interconnected Power Systems."

Coordinated efforts such as those described above must continue as conditions change and issues arise in order to maintain the safe, reliable, and economic operation of the entire interconnected bulk electric systems.

Impediments to New Transmission

Some proposed key transmission reinforcements required in various parts of the United States are being delayed or denied in the lengthy regulatory processes for issuing licenses. Because needed facilities are not in service as scheduled, during certain periods utilities have had to operate more costly generation or limit economy energy transfers to remain within reliability limits. In most cases, the ability of the systems to withstand generation or transmission facility outages has also been significantly reduced. If impediments to placing facilities in service, when needed, are not overcome, reliability will be jeopardized.

Examples of specific transmission projects that have been delayed are:

- The 243-mile Baltimore-Washington 500 kV loop has been delayed for more than 10 years by the certification process in Maryland. In October 1985, after many years of litigation, certification for the final segments of this loop was completed. The process of acquiring necessary zoning and building permits for construction of these segments has begun. The Burches Hill-Ox portion of the loop was placed in service in December 1986. Approximately 82% of the loop (198 miles) is now in service. Completion of the remaining segments (45 miles) of the loop is now scheduled for the early 1990's. The development of this EHV transmission network in the Washington, D.C. area will improve reliability of supply to the nation's capitol. It will also add to the stability margin of the systems and significantly increase the energy transfer capability among MAAC, ECAR, and SERC.

- The second Belle River-Jewell 345 kV line (22 miles of new construction) in Michigan is necessary to deliver power from the new Belle River Power Plant to the system load centers. Without this line, restrictions on energy transfers from Ontario Hydro to Michigan are required during certain circuit outages and adverse weather conditions. Application for a construction permit was made in January 1983 and approved by the Michigan Public Service Commission for an in-service date of July 1985. Condemnation and zoning litigation which had delayed construction is now complete. The line is expected to be in service in March 1989.

- The 41-mile Valley-Serrano 500 kV line in southern California has been delayed from early 1986 to mid-1987 or later when an easement to cross U.S. Forest Service lands was challenged by the U.S. Marine Corps. The Marine Corps has claimed the transmission line would interfere with its helicopter training activities. Delay of the line has impaired reliability in a 1,100 square mile area and has limited the capability to import economy energy from Arizona and New Mexico into California.

- The 50-mile Kathleen-Lake Tarpon 500 kV line in Florida was delayed when the license was not granted by the Florida Governor and Cabinet, the last step in Florida's transmission licensing process. The project will not be reconsidered until the Department of Environmental Regulation sets standards for acceptable electric and electromagnetic field intensities. Florida Power Corporation has filed an appeal on this decision.

- Application for certification of the 55-mile double circuit Salem-Zenith 345 kV line in Texas, which has been in the regulatory certification process for over 3 years, was rejected by the Texas Public Utility Commission in November 1986. This line was needed to increase transfer capability within ERCOT, to deliver energy from remote generation, and to provide for firm

power wheeling. An appeal of the PUC decision was filed in April 1987.

- Extensive regulatory delays have impeded the completion of 500 kV reinforcements in southwestern Ontario. The lines are needed to transmit the full output of the Bruce nuclear complex on Lake Huron, to maintain transfer capability between Ontario and Michigan, and to provide a reliable supply for the load in the southwestern portion of the province. A favorable decision has now been obtained. The delays had necessitated the installation of complex special protection systems.

Public Policy Issues

Continued operation of existing generation and transmission facilities, and implementation of utility plans for new facilities are often constrained by public policies and regulatory treatment. Timely and consistent regulatory actions will be needed to assure a reliable supply of electricity in the future.

Deregulation of the electric utility industry could seriously impact service reliability. One adverse result of deregulation is likely to be reduced cooperation and communication among utilities as a result of being forced into competitive situations. Any deregulation step must recognize the need to maintain system reliability.

Electric utilities and public policy makers are each responsible to electric utility customers for assuring an adequate level of electric system reliability.

Regulatory Considerations

Utility plans, based on expected load growth, provide for adequate transmission and generation facilities to assure reliable electric supply during the next ten years. Implementation of these plans, however, depends in part on future regulatory actions. This includes not only the licensing and rate treatment of new facilities but also the impact of possible new legislation. Some basic considerations in the development of all regulatory policies, including environmental or financial policies, should include:

- Recognition of the need for reliable electric supply.
- Consistent rulings on individual projects from initial authorization to completion.
- The need of investors to obtain a return commensurate with risk.
- Recognition of the technical characteristics and limitations of the bulk electric utility systems.
- Recognition of uncertainty in electric energy consumption.
- The need for timely approval and licensing of new generation and transmission facilities.

Efficient planning by utilities is possible only with timely and consistent regulation. If utilities cannot anticipate a reasonable range of regulatory action, they will be reluctant to commit to major expenditures. In some cases, the uncertainty of regulatory treatment has been compounded by a regulatory agency reopening or reversing its own prior action after a utility project had been started.

The uncertainty of a reasonable return on investment increases the reluctance by utility management to make commitments for needed new facilities or for capacity purchases. Complete or partial disallowance of investment in new generating facilities from the rate base has taken many forms. The result has generally been some combination of the following: (1) disallowance based on alleged mismanagement, (2) disallowance based on comparison with lower cost alternatives unavailable at the time of project commitment, and (3) disallowance or deferral of return based on the regulator's perception of current capacity needs. The Wolf Creek nuclear station is an example where all three measures were applied. Various portions of the plant cost were completely disallowed, revalued at the cost of hypothetical coal-fired capacity, or subject to deferred return.

The problem is not limited to the treatment of new generation. Similar disallowances of investments in transmission and the cost of capacity purchases have also occurred based on current cost comparisons with alternatives which were unavailable or not economical when the project was originally committed. While such use of hindsight serves to hold down rates for the short-term, the result is serious disincentive to commit for new facilities.

Recently there has been an increasing trend toward the use of the term "least-cost" planning. Least-cost planning principles must be applied with due consideration of the potential impact on reliability. While utilities and regulators support the concept, a significant problem is the lack of a common understanding of the meaning of "least-cost" and its application.

Overlapping jurisdiction of multiple regulatory agencies tends to extend the lead time required for major project completion. Obtaining certification of need and siting approval for a new project may involve several state

agencies and even Federal or local bodies. The cost and total time required to obtain all the required approvals present serious disincentives and, in some situations, may affect the economic evaluation of the project.

The Shoreham nuclear unit in New York is an example of conflict between state and local governments on one hand and the Federal government's Nuclear Regulatory Commission (NRC) on the other. In the case of Shoreham, local and state officials have refused to develop their own evacuation plans, refused to participate with the utility in the development of an evacuation plan, and refused to participate in the testing, required by the NRC, of the evacuation plan developed by the utility.

The Seabrook nuclear unit in New Hampshire is an example of conflict between two adjacent states, as well as between a state and the Federal government. In this case, evacuation plans originally developed by Massachusetts communities which are within a 10-mile radius of the plant were subsequently withdrawn, and the state of Massachusetts has refused to participate in the development of new evacuation plans.

In each case, these nuclear plants which are complete or essentially complete are being held up, aggravating reliability problems on Long Island and in New England.

Requirements for future electric supply reliability are often regional in nature—not confined to an individual state. Some regulators have denied approval of new transmission projects because the major direct benefits of the projects were to areas outside of their jurisdiction. One example is the now defunct plan for a new 500 kV transmission line from Manitoba, through the Dakotas, to Nebraska which was rejected by the South Dakota Commission. Additional general impediments to the construction of new bulk electric transmission lines include lengthy licensing procedures, and skepticism about reliability as the primary justification for new facilities.

Utilities and public policy makers must find ways to resolve these and other such policy issues more promptly if these groups are to meet their joint obligation of providing for reliable, economic service to electric utility customers.

Financial Considerations

Utilities are under pressure from many areas to minimize expenditures. The pressure can take many forms, such as regulatory action or competitive pressure to minimize rates. If utilities are forced to defer investments in new facilities, the result could be eventual deterioration of electric system reliability. One example is increased use of complex special protection systems to allow higher loadings on existing transmission facilities or to substitute for new transmission. While economically attractive, the potential degradation of reliability caused by the extensive use of these systems should also be considered.

One means of reducing costs is to reduce or postpone maintenance. However, the result of such action is likely to be deteriorating availability of generation and transmission facilities leading to gradual degradation of reliability or to an abrupt widespread blackout.

The impacts of a blackout are so great that a way must be found to balance the cost of maintaining reliability with the social and economic costs of a widespread blackout. The consequences of a blackout over a large area are much more severe than those of scattered outages—even if the total cumulative time of interruption is the same. For example, during scattered electric supply outages, people may be trapped in an elevator; however, community services are probably available to rescue them within a reasonable time. In a widespread blackout, normally adequate community resources may have difficulty coping with the large number of simultaneous similar emergencies.

Deregulation

Deregulation of the electric utility industry could seriously impact service reliability. Maintaining control and reliability of an interconnected bulk electric power system is far more complex than for a gas or telephone system and the consequences of system failure far more widespread. The coordinated planning and operational control of interconnected bulk electric systems is essential to reliable operation and must be addressed in any deregulation proposals.

One adverse result of deregulation is likely to be reduced cooperation and communication among utilities as a result of being forced into competitive situations. The reliable operation of the interconnected generation and transmission systems has been possible only with the close cooperation and exchange of information among the system planners and operators of the various utilities. Any reduced coordination of planning and operation as a result of deregulation would adversely affect reliability.

Deregulation will also tend to introduce greater uncertainty into the long-term planning for new capacity. For example, customers "shopping around" for bargain capacity with relatively short-term contracts may result in lack of long-term commitments for required new utility capacity. Under such conditions, no supplier would have long-term responsibility for supplying future customer loads.

Transmission Access

Through cooperative efforts, the NERC utilities have developed reliable and efficient interconnected transmission networks. The pros and cons of the concept of open access to the bulk electric transmission systems are currently being debated. Technical aspects of this concept must be examined very closely since reliability may be adversely affected.

The transmission networks were built to deliver energy from generating plants to load centers and to provide paths for that energy during facility outages. This includes provision for emergency support from neighboring systems. Utilities have also utilized the transfer capacity of the transmission network to make economy sales and purchases of capacity and energy with other utilities on an intraregional and interregional basis. These multiple uses of the transmission systems require a high level of continued coordination to assure that transmission facilities are not overloaded, that system stability is maintained, and that unforeseen line outages do not result in major service interruptions to customers.

Open access to the transmission network could have a detrimental impact on bulk system reliability because of power flows on the transmission systems in directions and magnitudes never envisioned.

Environmental Considerations

Disputes concerning environmental regulations and their interpretation often delay the construction of new facilities or preclude the use of already constructed facilities. This directly impacts reliability since new facilities may not be placed in service in time to meet a projected need.

Opponents of generation and transmission facilities have become very skilled at using a variety of environmental issues to block or delay needed facility construction. Frequently, these public intervenors use regulatory or judicial forums as well as the news media to generate public doubt about the safety or environmental impacts of proposed utility facilities. The controversial issue of health impacts of electric and electromagnetic fields has caused several critical transmission projects to be delayed, abandoned or even deenergized. (Examples have occurred in Texas, Florida, New York and other states.) Legislation to control electric and electromagnetic field strengths of transmission lines, if needed, should be developed carefully with a realistic evaluation of potential effects. Stringent requirements may have adverse reliability effects with no actual health benefit.

The issue of acid rain continues to be a major concern. The impact on reliability is still uncertain but could be substantial. Some general effects which impact available capacity can be identified. However, the degree of impact will depend upon the specific legislation. These impacts include:

- Existing units which are retrofitted with emission control equipment will usually have reduced net output due to an increase in the amount of power necessary to operate the control equipment and lower average availability because of increased complexity.
- Outage time of several months or more may be required to install the new emission control facilities on existing units.
- Older units may be prematurely retired if emission control retrofit is not considered economical.

As an example, the ECAR Region made a study in 1987 of the potential impact of the U.S. House of Representatives bill H.R. 4567 on the reliability of ECAR electric supply. The 1987 scenario assumed that each system in ECAR would limit total emissions to an average of 1.2 pounds per million Btu for sulphur dioxide and 0.6 pounds per million Btu for nitrogen oxides. It was estimated that older existing units with a total capacity equal to about 11% of the 1986 regional coal-fired capacity would have to be retired early. Another 4% capacity reduction would result from operation of the emission control equipment and decreased availability. The required new capacity would total about 15% of ECAR's 1986 coal-fired capacity. As an indication of potential national impact, extending the results of the ECAR study to the total United States would indicate the required new capacity would be in the range of 25,000 to 30,000 MW by 1996. The potential impact on reliability is substantial and should be carefully considered as new legislation is being developed.

Reliability — Effect on Customers

At every instant, the supply of electricity must equal the demand for electricity. This supply includes not only generation capacity but adequate facilities to transfer the generated electricity to the customer load.

The utilities are planning to have adequate resources to reliably meet customer demands over the next ten years. However, if an adequate supply to all utility customers cannot be maintained, the only recourse available to the electric utility will be the application of emergency procedures. These procedures may impact the quality of service to the customer, even to the extent of interrupting the electric supply to some customer loads, in order to protect the overall integrity of the bulk electric systems.

Demand and Supply Balance

The reliability of electric service available to the customer is governed by the design of the electric systems and by the conditions under which the systems must operate. The reliability level is also determined by facility performance, the scheduling of adequate generation, the management of energy interchange transactions within and among regions, and the scheduling of maintenance outages of generation and transmission equipment.

From time to time, conditions can occur for which the systems are not designed. Even when capacity margins appear adequate, there are combinations of common occurrences which can place the systems in a vulnerable position. An unusual amount of forced generation or transmission outages or an unexpected high customer demand level are examples of these possibilities. Under these conditions, shortage in supply can develop very quickly.

At every instant, the supply of electricity in all areas must equal the demand for electricity. Thus, when conditions occur that result in a shortfall of generation or transmission supply, customer load must be reduced to the level that can be supplied. During any electric supply and demand imbalance, there is a danger of an uncontrolled shutdown of the entire electric system with possible damage to generation, transmission, and customer equipment—possibly accompanied by large costs to the utilities and their customers. To prevent such system wide impacts, emergency operating procedures may become more widely used in the next ten years.

Effect of Decreased Reliability on Customers

The impact on electric utility customers of a potential shortfall of adequate generation or transmission capacity can perhaps be understood through a brief explanation of the emergency procedures available to electric utilities. These procedures are currently in place and will be applied as necessary in the event of transmission or generation inadequacy. The procedures are generally implemented after all emergency electricity generating sources have been called upon and after contractually interruptible customer loads, including those under load management, have been interrupted. The procedures are not necessarily listed in the sequence of application but generally include:

- Public Appeals—An electric utility request to the public through the news media, primarily radio and television appeals, to voluntarily reduce electrical consumption. This can show results in about an hour or more.
- Industrial Appeals—Telephoned electric utility requests to large industrial customers to reduce load. This can be effective within one to two hours.
- Voltage Reductions—An action taken by an electric utility to reduce the voltage on its distribution system by as much as 8%. This can be effective within several minutes or may take up to several hours, depending upon the equipment installed and the advance preparation made by the utility.
- Controlled Load Shedding—An orderly action taken by an electric utility to lower customer demand to the level of available generation or transmission capacity. This can be accomplished within a few minutes. Load shedding involves interrupting distribution feeder circuits, which supply customer loads, on a rotating basis. Rotation of customer interruptions minimizes the duration of individual customer outage time during a system emergency. Coupled with this interruption procedure is a planned restoration procedure. As utility system capacity is restored, portions of the shed load are

gradually reconnected until all the customers are returned to service. If possible, electric utilities will usually use television and radio appeals to give the public a chance to reduce demand voluntarily before utility controlled load shedding is implemented.

Additional actions may be taken by governmental authorities. This could occur when they are advised by an electric utility that severe and prolonged generation or transmission shortfalls are forecast in the future with no alternative available. The action would be in the form of a legislated or mandated curtailment.

Adequate Reliability

Electric utilities, regulators, governmental and legislative bodies, and the public share to various degrees in the responsibility for ensuring an adequate level of bulk electric system reliability to meet future electricity requirements. All of these groups must work together to support the general premise of a continuing adequate, reliable, and affordable electric supply. As the social and economic impacts of an inadequate electric supply can be widespread and costly, reliability problems and issues should be addressed and resolved quickly and fairly for the mutual benefit of all.

Regional Assessments

The remainder of this report assesses the bulk electric system reliability of the nine Regional Reliability Councils.

SUMMARY OF 1996 PROJECTIONS FOR THE REGIONAL RELIABILITY COUNCILS

Region	Summer Peak Demand (Thousands of MW)	Annual Net Energy for Load (Millions of MWh)	Summer Installed Capability (Thousands of MW)	Transmission System[a] (Circuit Miles in Thousands)
ECAR	82.1	467	105	16.2
ERCOT	50.3	263	56	8.1
MAAC	42.4	231	53	6.9
MAIN	41.9	211	50	5.6
MAPP	30.5	167	39	21.9
NPCC[b]	91.4	614	123	33.8
SERC	129.1	681	156	28.9
SPP	55.4	266	67	12.5
WSCC	118.1	706	155	68.6
NERC-TOTAL	641.2	3606	804	202.5
NERC-U.S.	577.1	3116	708	156.6
NERC-CANADA[b]	62.9	484	95	45.5
NERC-MEXICO[c]	1.2	6	1.4	0.4

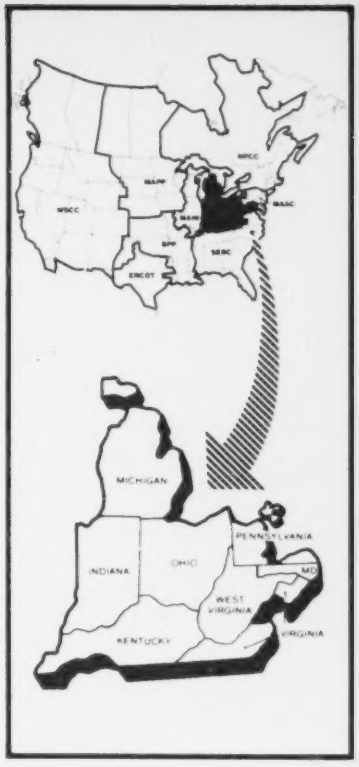
[a]Includes ac and dc transmission lines operating at 230kV and above as of December 31, 1996.

[b]NPCC and NERC-Canada are winter peaking with 1996/97 winter peak demands of 107,000 MW and 86,200 MW, respectively. Winter installed capability for 1996/97 winter are projected to be 126,200 MW for NPCC and 96,000 MW for NERC-Canada.

[c]Includes only that part of the Comision Federal de Electricidad system in the northern portion of Baja California, Mexico, which is interconnected with the U.S. systems.

ECAR

East Central Area Reliability Coordination Agreement



The electric power supply planned in the ECAR Region will satisfy the ECAR reliability criteria provided that availability of generating equipment continues at present levels, and load and capacity conditions are as projected. However, a small decline in the availability of generating equipment coupled with a slight increase in the rate of load growth, or other factors such as implementation of acid rain control strategies could quickly reduce the future power system reliability to unacceptable levels.

The transmission network in ECAR is judged to be adequate to handle a wide range of contingencies. This judgment is based on analysis and review of power transfer capabilities within ECAR and between ECAR and neighboring regions. Regional transmission appraisals as well as studies conducted by member companies have repeatedly demonstrated the strength and flexibility of the existing and planned transmission systems in ECAR.

	Actual	Forecast		
Summer / Winter	1986 / 1986/87	1987 / 1987/88	1996 / 1996/97	Growth Rate (%/year)
Summer Peak—MW	69,606	70,056	82,081	1.8
Winter Peak—MW	64,561	68,721	80,447	1.8
Annual Energy—GWh	390,245	399,000	467,200	1.8
Installed Capability (summer)—MW	95,201	97,566	104,815	0.8

Demand Projections

The aggregate of the demand projections provided this year by systems in ECAR shows that the Region is expected to be summer peaking throughout the 1987-1996 period. The average annual growth in projected peak demand for the period 1987-1996 is approximately 1.8% for both summer and winter, as compared to 2.1% one year ago.

Capacity Resource Additions

Three coal-fired units totaling 1,109 MW were placed in service during the first half of 1986. Six of the 7 generating unit additions that are presently under construction in ECAR are scheduled to be available for service during the first 5 years of the forecast period. Three nuclear generating units (Fermi 2, Perry 1 and Beaver Valley 2—3,131 MW total) are scheduled during 1987 and 3 coal-fired units (Rockport 2, Zimmer 1 and Trimble County 1—3,095 MW) are scheduled during 1988-1991. Non-utility generation projects totaling 2,031 MW and 1 utility combustion turbine (19 MW) are also projected to be available for service during this first 5-year period. However, there is uncertainty associated with any construction schedule and one or more of these additions may be delayed because of circumstances such as construction difficulties or licensing problems. Further, the significant megawatt increase in non-utility generation reflects a material change in the ECAR capacity planning environment. This will add a new dimension of uncertainty to the planning process if non-utility generation is not installed and operated consistent with utility standards of service reliability.

Very little capacity is scheduled to be placed in operation during the 1992-1996 period. The lead time required for new capacity additions would make it virtually impossible to react to higher than projected load growth or an unexpected loss of capability (e.g., impact of potential acid rain legislation) in a timely manner. The generating

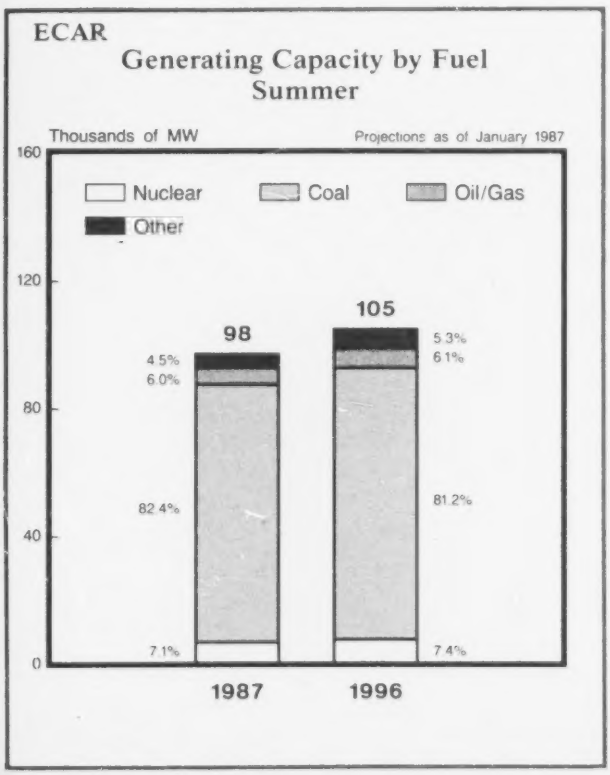
unit additions projected during this 5-year period consist of 1 coal-fired unit (600 MW), 12 combustion turbines (975 MW), and 4 non-utility generation projects (440 MW). However, a contingency quantity (-180 MW) is included in the 10-year plan to recognize that not all of the non-utility generation projects are expected to be developed.

Adequacy of Projected Generating Capacity Margins

Extensive appraisals of the adequacy of projected generating capacity margins have been carried out within ECAR using probabilistic techniques and procedures. The appraisals are based on consideration of the regional pattern of daily peak demands for each month of the study period, the status of scheduled generating unit additions, and the expected availability of generating equipment.

The availability of generating equipment is the most critical parameter and high availability continues to be a goal of ECAR members. However, it may be increasingly difficult to maintain power plant availability at the favorable high levels experienced in recent years. Capacity margins will continue to decrease over the period, placing greater demand on generating units. In addition, by the end of the forecast period, the age of approximately 14% of the generating capacity in ECAR will be 40 or more years and approximately 27% will be 30 or more years. Environmental restrictions and any mandated additions of emission control equipment could further degrade the equivalent availability of generating equipment.

The 1987 ECAR appraisal shows that if the load and capacity are as projected, the ECAR criterion for judging the adequacy of the projected installed generating capacity will be satisfied throughout the 1987-1996 period provided that availability of generating equipment continues to exceed 73%.



Impact of Proposed Acid Rain Legislation

During recent years, a number of acid rain bills have been introduced in the United States Congress. Since coal is the predominant fuel used by the power plants within the ECAR area — accounting for over 95% of the total electrical energy generated during 1986 — the impact of compliance with acid rain legislation could be very severe on individual ECAR member systems and their customers.

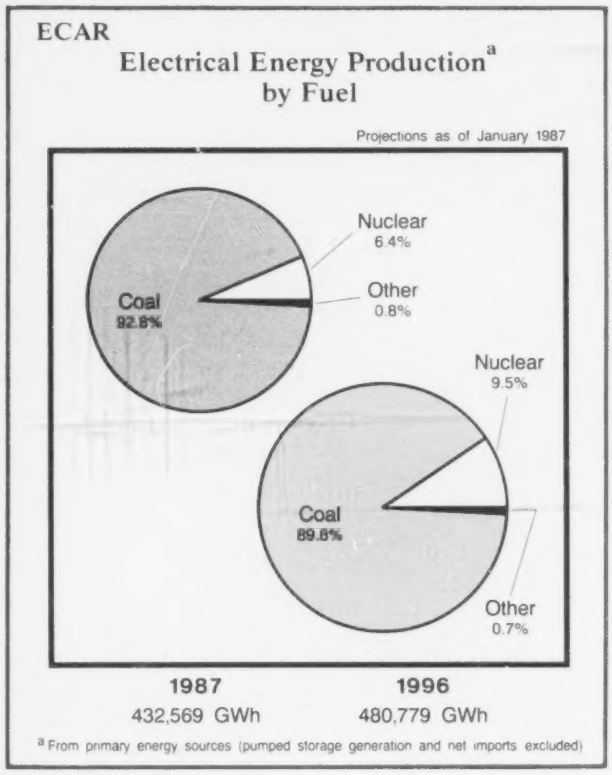
In each of the past few years, scenarios were developed which provided results encompassing the probable range of the impact that such legislation could have on reliability and adequacy of bulk electric power supply in the ECAR area. The scenario developed for the 1987 assessment was based on the assumption that each system in ECAR would limit average annual emissions for fossil-fired units to 1.2 pounds per million Btu for sulfur dioxide (SO_2) and 0.6 pounds per million Btu for nitrogen oxides (NO_x). A possible control strategy for achieving these emission limits was identified by each system of ECAR. In those instances where it was not feasible to quantify the effect on reliability of the assumed control strategy, the impact was considered to be negligible.

The results indicated a very adverse effect on the adequacy of ECAR generating capacity. In order to achieve the targeted average annual emission levels and still maintain a reliability level equivalent to that provided for 1996 by the current 10-year capacity plan, at least 12,000 MW of additional new generating capacity will be required. This additional new capacity would be needed to: (1) offset the poorer availability of some of the generating units retrofitted with emission controls and (2) replace approximately 9,600 MW of capacity lost because of premature retirement, additional auxiliary power requirements, and other deratings associated with necessary plant modifications.

Fuel and Electrical Energy Production

The high dependence of ECAR member systems on coal-fired generation makes it imperative that continuity of future coal supplies be maintained and electric utility systems be permitted to burn the significant quantities of locally produced coal needed to satisfy the future electric energy requirements in the Region. Over the forecast period, coal-fired generating capacity will supply about 90% of the electrical energy production in ECAR.

Nuclear is projected to increase its share of total electrical energy production from 6.4% of the total in 1987 to 9.5% in 1996. The availability of materials and services for the nuclear fuel cycle (uranium conversion, enrichment and fabrication) will continue to be adequate to meet requirements in ECAR for the foreseeable future. However, issues involving spent fuel storage and disposal must still be resolved.



Transmission System

The electric utility systems in ECAR have developed an extensive and reliable high voltage and extra high voltage (EHV) transmission network that is interconnected with the networks in neighboring regions at various voltage levels. The EHV portion of the network in ECAR consists of over 2,000 miles of 765 kV, over 800 miles of 500 kV and over 11,700 miles of 345 kV transmission. The final 97-mile link in the 765 kV transmission network, as it was initially projected, was placed in service during 1986. Current plans call for the addition of approximately 100 miles of 500 kV and 300 miles of 345 kV transmission during the 1987-1996 period. These planned additions will enhance but not significantly alter the bulk transmission network that exists today.

In recent years, fuel cost differentials have created numerous opportunities for large scale economy energy transfers. These transfers are in addition to the long duration energy transfers scheduled well in advance. Significant amounts of energy transfer have been arranged on a daily and an hourly basis. These intraregional and interregional transfers have become routine and will continue to be an important consideration in the operation of the interconnected transmission systems for the foreseeable future. These multi-party transfers have caused power flow patterns that were not anticipated at the time the systems which comprise the interconnected network were originally planned, and they will continue to challenge the ability of operators to maintain a high level of reliability. This will be particularly true with the reduced operating margins that will be available.

Intraregional transmission system performance studies are conducted by ECAR to assure that the member systems meet regional reliability criteria. In addition, ECAR participates with neighboring regions in system performance studies as part of the activities related to the MAAC-ECAR-NPCC, VACAR-ECAR-MAAC, and MAIN-ECAR-TVA interregional coordination agreements. These agreements provide for exchanges among the parties of information related to bulk electric power supply reliability and for review and analysis of such information. Transmission performance studies are conducted prior to each summer and winter peak load season and, on an annual basis, for some future period of interest. The purpose is to provide assurance that the planning and operation of the interconnected systems are properly coordinated. These studies provide insight into the expected performance of the bulk electric power supply network under a wide range of system conditions and examine the ability of the transmission network to support large-scale energy transfers. Through such studies, coordination procedures and operating guidelines are developed or improved to assure that the interconnected network will be operated in a reliable manner.

System Operations

Extensive intersystem and area communication facilities are used by ECAR and its members to coordinate normal and emergency system operation among the electric power control centers within ECAR and with neighbor-

ing regions. The communication/computer network, which interconnects the electric power control centers and the ECAR office, is used to exchange operating information and to quickly disseminate abnormal condition reports (i.e., a sudden loss of generation, the tripping of an important transmission line, or the cause of an unusual transmission system loading pattern).

Several systems are in the process of designing or implementing improvements to control centers that will incorporate system security procedures and analytical capabilities which will allow system operators to carry out on-line evaluations of system security. ECAR systems, in conjunction with the systems in MAAC, NPCC and SERC, are actively studying the technical and economic feasibility of computer-to-computer data links for the exchange of real-time system data. Such communication links could greatly expand the base of information available to evaluate on-line system performance.

The East Central Area Reliability Coordination Agreement (ECAR) Region bulk power membership currently consists of 27 companies (18 systems) which serve either all or part of the states of Michigan, Indiana, Kentucky, Ohio, West Virginia, Virginia, Pennsylvania, Maryland and Tennessee.

ERCOT

Electric Reliability Council of Texas

Based on current generation and load forecasts, capacity margins for the Region will vary from 19.8% in 1987 to 16.6% in 1996. Transmission system utilization for energy and capacity transfers has increased and is expected to be an important factor in the future reliability of the Region. The projected growth of non-utility generation has slowed, as have projected load growth rates. The downturn of the oil and gas industry has significantly reduced the growth of most systems within ERCOT.

	Actual		Forecast		
	Summer / Winter	1986 / 1986/87	1987 / 1987/88	1996 / 1996/97	[1] Growth Rate (%/year)
Summer Peak—MW		39,335	39,072	50,329	2.9
Winter Peak—MW		28,730	31,581	44,787	4.0
Annual Energy—GWh		190,796	195,815	263,409	3.3
Installed Capability (summer)—MW		43,386	44,405	55,931	2.6

Peak Demand and Energy

The summer peak hour demand forecast by ERCOT member utilities indicates an average annual growth rate of 2.9% for the period from 1987 through 1996, a reduction from the 3.5% rate projected last year. Winter peak hour demand is forecast to grow at 4.0%. Load management and conservation programs are being pursued by member utilities, and are expected to account for approximately 3,200 MW of demand reduction by 1996. Cumulative annual energy growth from 1987 to 1996 is currently estimated at 3.3%, compared to 4.0% forecasted for the 1986-1995 period. The downturn in the oil and gas industry is the primary cause of the reductions in peak demand and energy growth rates.

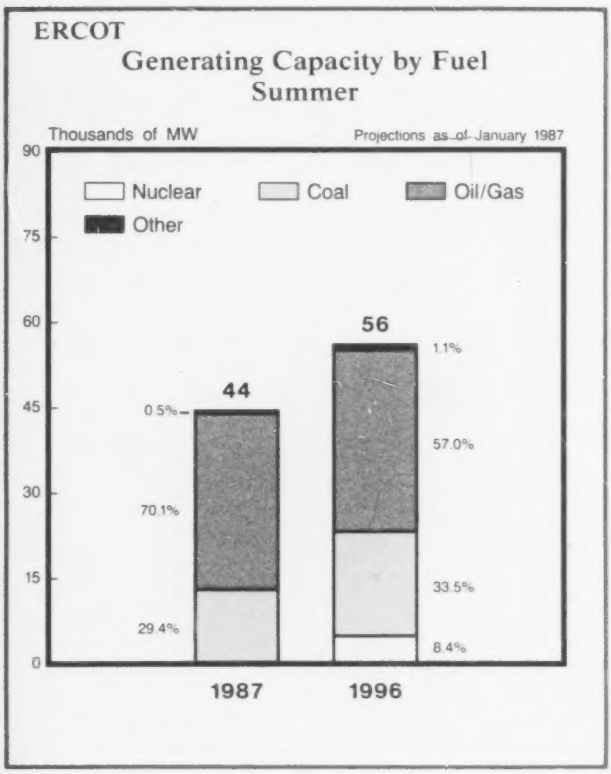
Generating Capacity and Fuel

During 1986, 1,203 MW of new utility-owned generating capacity were added to the ERCOT system. New generating capacity scheduled for installation during 1987 through 1996 is approximately 14,436 MW. This includes 5,415 MW of coal-fired capacity, 56 MW of utility-owned refuse burning capacity, 2,865 MW of combustion turbines, and 4,800 MW of nuclear generation. No fuel type has been designated for the remaining 1,300 MW. Rerating of existing units is expected to add 286 MW, while retirements during the period are expected to remove 2,199 MW. The total net increase in capacity is 12,523 MW, an 18% reduction compared to last year's forecast. Non-utility generation, mainly cogeneration, is forecast to increase by only 102 MW during the forecast period. Current projections indicate that 2,373 MW or 5.0% of 1987 summer peak capacity resources and 2,475 MW or 4.2% of the 1996 summer peak capacity resources will be supplied by non-utility generation.

The first of the Region's four nuclear units, South Texas 1, is scheduled to become operational in December 1987. The second South Texas unit is scheduled to be completed in 1989, and the two Comanche Peak units are scheduled for 1989 and 1990.

Electric energy generation by ERCOT members was 42% coal or lignite, and 57% gas in 1986, changing to 50% coal or lignite, 38% gas, and 11% nuclear in 1996. Remaining minor amounts of generation are from hydro, oil, and other resources. Net imports from non-ERCOT systems, including purchases from non-utility generators, amounted to 10.7% of net energy for load in 1986, and are projected to be 12% in 1996.

The capacity margin within the Region is expected to range from a high of 23.5% in 1989 to a low of 16.6% in 1996. Capacity purchases, principally from non-utility generators, are being used to supplement ERCOT capacity on both a short- and long-term basis. Projected capacity margins exceed the planning guidelines adopted by the Region, thus planned capacity resources are expected to be adequate during the 1987-1996 period.



Transmission

ERCOT members expect to install approximately 1,305 circuit miles of 345 kV lines during the next 10 years. This represents a 15% reduction from the 10-year projections made in 1986.

In addition, plans are currently being developed for the expansion of the North DC Tie between ERCOT and the Southwest Power Pool from 200 MW to 300 MW in 1989. The South HVDC Tie is currently on hold, pending the outcome of a proposal to establish an alternate tie in Eastern Texas. The alternate tie is anticipated to have a capacity of 600 MW, which is an increase of 100 MW over the previous South Tie proposal. Completion of the East Tie is tentatively scheduled for 1990.

A major transmission concern within ERCOT is the status of an existing double circuit 345 kV line interconnecting Houston Lighting & Power Company (HL&P), TU Electric, and Texas Municipal Power Agency. In November 1985, a county court found that HL&P had abused its discretion in acquiring right-of-way for the lines, and ordered the lines deenergized. An Appeals Court ruled in HL&P's favor regarding reenergizing the circuits, but the State Supreme Court has since ordered that the lines remain deenergized throughout the appeal process. No decision has yet been rendered in the appeal of the case before the Appellate Court. Because timely legal resolution was unlikely, and because of the critical need for these facilities to accommodate wheeling transactions, HL&P applied for a Certificate of Convenience and Necessity from the Texas Public Utility Commission to reroute a portion of the line around the property in question. Approval of the Certificate was given in April 1987, and construction of the reroute is expected to be complete by September 1987.

The proposed Salem-Zenith interconnection, a critical 345 kV double circuit interconnection between HL&P and the Lower Colorado River Authority, was rejected by the Texas Public Utility Commission in November 1985. This line is critically needed to support bulk electric power transfers, and the PUC decision is being appealed to the courts.

The delays resulting from the regulatory and judicial impediments mentioned have impacted over 500 circuit miles of bulk transmission facilities within ERCOT. Continued problems of this nature present a serious reliability concern to the ERCOT Region.

Energy and Capacity Transfers

Due to the fact that transmission improvements within ERCOT have not proceeded as planned, a considerable increase in loading of existing transmission has occurred. Further increases are expected due to various forms of inter-utility and non-utility generation wheeling. During 1986, the wheeling of firm electric power accounted for 2,148 MW of capacity. This is equivalent to 5.5% of the regional peak demand for 1986. Also in 1986, 2,296 GWh were transferred by economy and brokerage transactions.

The wheeling of non-utility generated energy and capacity continues to play an important role in the future devel-

opment of non-utility generation within ERCOT. In 1986, 1,328 MW of non-utility generation were wheeled by ERCOT utilities from the host utilities to other purchasing utilities. This means that 60% of the non-utility generation capacity under contract within ERCOT in 1986 was wheeled to utilities other than the connecting utility.

The increasing utilization of transmission facilities for wheeling has been, and will continue to be, a significant reliability concern within ERCOT. During 1986, 13 instances occurred where economy transactions were interrupted due to insufficient transmission capacity. The situation has been aggravated by the impediments which have occurred in the construction and operation of needed transmission facilities. With greater utilization of the transmission grid being projected, future reliability within ERCOT cannot be expected to remain at current levels without the completion of planned transmission improvements.

Operations

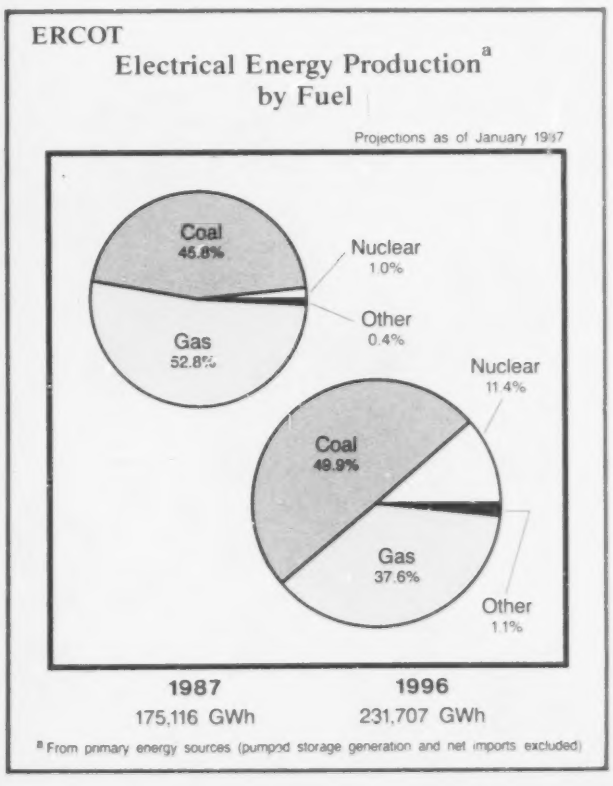
Operations within ERCOT have been enhanced by the adoption of procedures for handling intersystem exchanges of both firm and economy energy. Additionally, the third annual session of dispatcher training has been completed. All system dispatchers within ERCOT have received this training.

During 1986, three task forces were created to address reliability related issues. The first of these was a Communications Task Force, which evaluated the availability of existing communication systems in the event of an ERCOT blackout. As a result, emergency power equipment is being upgraded. This Task Force also identified utility-owned microwave paths that could be used to link the two security centers and associated control areas, thereby reducing dependence on leased circuits for those critical functions. The Task Force is also identifying alternate communications (microwave, UHF radio, etc.) that could be utilized in the event of loss of the primary microwave paths. The Task Force is also generating updated microwave system documentation to better support current and future communication projects and other ERCOT projects, such as the Black Start Task Force.

The Black Start Task Force was created to develop overall restoration procedures in the event of a Regional blackout. Final recommendations from this Task Force are expected by the end of 1987.

An additional task force was created to evaluate the adequacy of ERCOT's spinning reserve criteria. The scheduled addition of large individual generating units in both North and South ERCOT prompted the creation of this task force, and recommendations will be forthcoming.

Increased utilization of the transmission network, together with the inability to complete necessary transmission system improvements, and the integration of large numbers of non-utility generators have all served to increase the operational complexity of the ERCOT system. These mounting problems are expected to force operation of the system in a condition closer to minimum acceptable margins than ever before.



Reliability Issues

The key reliability issues of most concern to the ERCOT member systems are as follows:

- **Transfer Limitations**

  The increased usage of the ERCOT transmission system for both economy and firm electric power interchanges has placed a significant strain on certain portions of the existing transmission network. Of particular concern is the fact that the transmission system currently being operated is not the system that was planned. In the future, increased use of the transmission system is expected to occur as a result of emphasis on economy transfers and non-utility generation

wheeling. Unless planned transmission system improvements can be made as scheduled, interruption of wheeling transactions may be expected to occur more frequently.

- **Non-Utility Generation**

  Current forecasts indicate that up to 2,475 MW of the capacity within ERCOT by 1996 will be in the form of non-utility generation facilities. The long-term reliability of such facilities has yet to be established, and concern exists over issues such as the non-utility generator's dependency on natural gas for fuel, unit dispatchability, wheeling, minimum load constraints, and long-term availability. The future impact of non-utility generation on the reliability of electric supply within ERCOT remains uncertain.

- **Capacity Completions**

  Two major nuclear projects represent the bulk of additional capacity expected to be completed within ERCOT during the next few years. South Texas 1 (1,250 MW) is scheduled to be on line before the summer peak of 1988, and South Texas 2 (1,250 MW) is expected to be on line before the summer peak of 1989. Revised schedules for the completion of Comanche Peak (2-1,150 MW units) now indicate that the first unit will be on line by summer peak of 1989 and the second unit by summer peak of 1990. Collectively, these 4 nuclear units represent 38% of the expected increase in ERCOT capacity during the next 10 years. As is the case with all nuclear units, there is considerable technical, regulatory, and political uncertainty associated with bringing these units on line. Should unforeseen impediments occur, ERCOT could incur significant risks to the adequacy of the future electric supply.

- **Natural Gas Supply**

  ERCOT utilities depend heavily on natural gas as a boiler fuel. Approximately 38% of ERCOT's energy production in 1996 will be fueled by natural gas. Because of this dependency, the long-term availability of natural gas as a boiler fuel is a major concern. While ERCOT utilities are currently benefiting from abundant supplies and attractive prices for natural gas, low gas prices have resulted in reduced drilling activities and deterioration of long-term reserves. ERCOT utilities have vigorously pursued fuel diversification. However, increased dependence on natural gas caused by purchases of energy supplied by gas-fired non-utility generation, delays in the completion of lignite and coal-fired generation, and life extension programs being applied to gas-fired generation all indicate continued reliance on gas as a fuel within the ERCOT Region which may impact reliability in future years.

The Electric Reliability Council of Texas (ERCOT) is comprised of 20 municipalities, 49 cooperatives, 6 investor-owned utilities and 1 state agency. These systems operate 85% of the electric generation in Texas and serve approximately 195,000 square miles—73% of the area of the state.

MAAC

Mid-Atlantic Area Council

Projected generating capacity margins and bulk power transmission capability for the 1987-1996 period are judged to be adequate to meet MAAC reliability objectives based on current peak demand forecasts and planned generation and transmission additions. About half of the capacity expected to be added in MAAC over the next ten years is non-utility generation. If this non-utility generation is installed as scheduled, remains in business and performs well, reliability could be enhanced. Conversely, reliability could be adversely affected if the non-utility generation does not develop, ceases operation prematurely, or does not perform as well as currently expected. Other factors that could adversely affect reliability include higher than projected growth in peak demand, delays of planned generating and transmission facility additions, unanticipated generator maintenance outages in peak periods, and reductions in existing coal-fired capacity due to proposed acid rain legislation.

Disturbances caused by the sudden loss of generating sources in other regions can significantly increase power flows on the MAAC transmission system. Parallel path flows caused by energy transfers in neighboring systems also increase power flows on the MAAC system. Because of these effects, a high degree of coordination in planning and operation is taking place between MAAC and systems in neighboring regions to ensure that adequate reliability is maintained.

	Actual	Forecast		
Summer / Winter	1986 / 1986/87	1987 / 1987/88	1996 / 1996/97	Growth Rate (%/year)
Summer Peak—MW	37,564	38,000	42,355	1.2
Winter Peak—MW	32,807	34,017	40,226	1.9
Annual Energy—GWh	197,056	199,428	230,949	1.6
Installed Capability (summer)—MW	47,626	48,731	53,032	0.9

Peak Demand and Energy

The summer peak demand experienced by the MAAC Region on July 7, 1986, was 37,564 MW which was 511 MW or 1.4% above the August 15, 1985 record peak. This was the fourth consecutive year that all-time peaks have occurred in MAAC. Annual energy for 1986 was 3.9% above the previous record year of 1985. Actual peak demands and energy figures for 1986 are shown above along with projections for 1987 and 1996. Peak demands for the 1987-1996 period have been reduced to reflect direct control load management programs. For example, the forecast 1987 and 1996 summer peak demands have been reduced by about 500 MW and 1,650 MW respectively to reflect projected direct control load management.

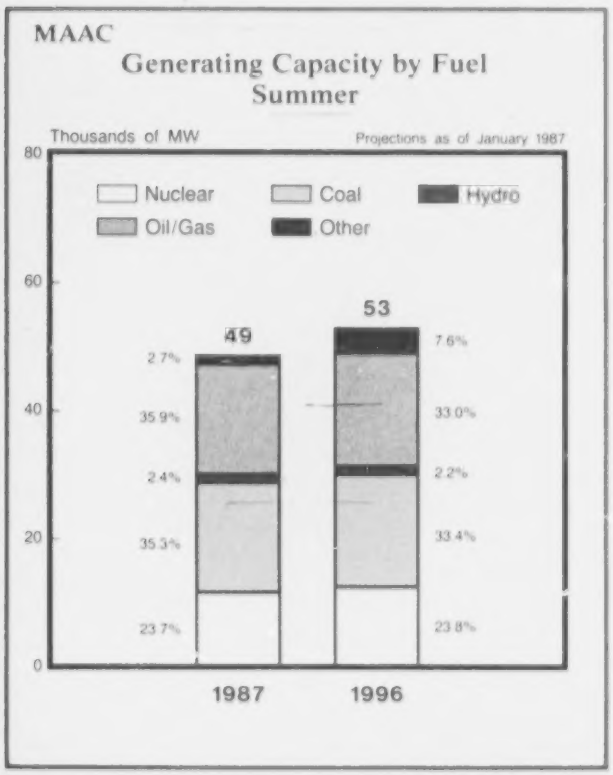
The projected 1987 summer peak is 951 MW higher than was projected last year for 1987 reflecting recent actual demand experience. The higher near-term demand and slightly higher projected growth rates result in a 1,233 MW increase in 1995 projected summer demand compared to last year's projection. Similarly, the projected 1987 annual energy is 5,419 GWh higher than was pro-

jected last year for 1987. In addition, there is a 6,547 GWh increase in 1995 projected annual energy compared to last year's projection.

MAAC has traditionally been summer peaking. With winter peak demands growing faster than the summer peaks, there is a long-term trend toward MAAC becoming a winter peaking Region. The 1987 summer peak is expected to exceed the preceding winter peak by 15.8%; by 1996, the summer peak is projected to exceed the preceding winter peak by only 7.0%. However, the Region is not expected to cross over to winter peaking until after the turn of the century.

Capacity Resources and Adequacy

Nuclear generating capacity increased significantly in 1986. Three Mile Island (TMI) 1, rated 776 MW, returned to full power operation early in 1986 after being out of service since TMI 2 suffered reactor damage on March 28, 1979. Limerick 1, a 1,055 MW nuclear unit, went into commercial operation in February 1986 and Hope Creek 1, a 1,067 MW nuclear unit, was made available for full service operation in December 1986. These additions, in combination with retirements and reratings of existing units, bring the existing MAAC capacity to 48,731 MW by the start of the 1987 summer period. The 1987 capacity is shown by fuel type on the adjacent bar chart.



A total of about 5,400 MW of new generation is planned to be added to the MAAC system while 1,100 MW of existing generation are planned to be retired or derated over the 1987-1996 forecast period. The additions include one 1,055 MW nuclear unit and one 640 MW coal-fired unit, both of which are well under construction. Also included are about 2,500 MW of non-utility generation, other small unit additions and existing unit reratings. As now scheduled, by the summer of 1996, MAAC will have 53,032 MW of installed capacity. The 1996 capacity is shown by fuel type on the adjacent bar chart.

The capacity margins projected for the MAAC Region for the next 10 years indicate that, as planned, sufficient generating capacity will be available to the MAAC Region through the 1987-1996 period to reliably serve the forecast MAAC peak demand. Capacity margins are forecast to range from about 24% in the early part of the period to about 21% by 1996.

The *Reliability Principles and Standards for Planning the Bulk Electric Supply System of MAAC* (as adopted July 18, 1968) states: "Sufficient megawatt generating capacity shall be installed to ensure that in each year for the MAAC system, the probability of occurrence of load exceeding the available generating capacity shall not be greater, on the average, than one day in ten years. Among the factors to be considered in the calculation of the probability are the characteristics of the loads, the probability of error in load forecast, the scheduled maintenance requirements for generating units, the forced outage rates of generating units, limited energy capacity, the effect of connections to other pools, and network transfer capabilities within the MAAC system." The capacity plans for the MAAC Region are developed consistent with this reliability criterion.

Reliability Issues

Factors which may adversely affect the adequacy of MAAC's future capacity are delays in the installation of new generating capacity, lack of facilities for disposal of nuclear waste, the enactment of more restrictive regulations governing SO_2 emissions from existing coal-fired electric generating plants, peak period generator maintenance, an accelerated trend toward a transition of MAAC from a summer to winter peaking region, and peak demand and energy requirements exceeding forecast.

Sufficient fuel is expected to be available to provide an adequate supply of energy to the Region over the review period. While the supply of nuclear fuel is judged to be secure, issues involving spent fuel storage and disposal must be resolved, particularly for older nuclear units. The passage of the Nuclear Waste Policy Act of 1982 represents a step toward resolving these issues. Meeting the

stipulations of this Act within the prescribed time frame will contribute to the continued operation of these units, thereby maintaining their significant contribution to adequate capacity supplies.

With a major percentage of the Region's capacity and energy requirements being produced by coal-fired plants in 1987, proposed acid rain legislation would result in restricted operation of existing coal-fired plants and could severely affect the Region's reliability. If such regulations become reality, some older coal-fired units, now part of MAAC's installed capacity, may have to be retired while the output of other plants may have to be reduced. Additionally, the installation and maintenance of any required new emission control equipment would be expected to reduce plant capacity ratings and availability.

Many MAAC companies are engaged in life extension programs to postpone the retirement of units. Others have scheduled retirements based on age, efficiency or capacity requirements. If all MAAC units in service over 40 years were retired, installed capacity could be inadequate by the mid-1990's. Therefore, life extension plans and proper recognition of unit retirements are important.

Some maintenance and refueling is now being done in MAAC during peak demand periods. These planned maintenance outages, together with unanticipated maintenance outage extensions, forced outages, and unexpectedly high peak demand could cause precariously low operating capacity margins for short periods. Normally, MAAC is able to meet demand requirements during these brief shortages by importing energy from adjacent systems and, if necessary, implementing emergency operating procedures. The forecast change in load shape sometime after the year 2000 in the MAAC Region from summer to winter peaking is expected to cause MAAC companies to perform additional periodic planned maintenance during peak periods. Thus, the installed capacity objective will have to accommodate those unit outages which cannot be scheduled for non-peak seasons.

A significant risk to the reliable operation of MAAC over the next 10 years is higher than forecast load growth. MAAC capacity margins may be inadequate in the mid-1990's with a 1.6% per year peak load growth (1.2% per year is currently forecast from 1987-1996) even if all planned new capacity is installed on schedule.

Non-Utility Generation

There is considerable potential for development of non-utility generation within the MAAC Region. About 3,300 MW of non-utility generation are anticipated in MAAC load and capacity projections by 1996 including 2,800 MW that is to be installed over the next 10 years. If less than about 2,000 MW of this non-utility generation materializes, generating capacity may be inadequate in the latter part of the forecast period.

Many issues remain to be resolved to properly incorporate non-utility generating facilities into the planning and operation of the electric system. The effect these facilities will have on reliability of suppy in MAAC is a function of many factors, including their availability, willingness to coordinate maintenance schedules, effect on transmission systems, and effect on light load operation if the non-utility generation facilities are not dispatched in coordination with utility capacity.

Reliability could be adversely affected if non-utility generation included in the forecasts is not developed, ceases operation prematurely or if the performance characteristics are substantially below those currently projected for the facilities. System reliability could also be adversely affected if the installation and operation of non-utility generation (connected to a system that was not originally designed for additional generation) are not coordinated with installation of required transmission reinforcements and operation of the integrated electric supply system. Alternatively, if the non-utility generation facilities are installed when scheduled, remain in business, and perform well as an integrated part of the supply system, reliability could be enhanced.

Transmission System

The MAAC transmission system is a network of 1,660 miles of 500 kV transmission lines which overlay and interconnect the network of 4,660 miles of 230 kV lines and 170 miles of 345 kV lines. These mileages reflect 30 miles of 500 kV lines and 20 miles of 230 kV lines added in 1986. Since 1982, 2,381 Mvar of capacitors have been installed on the 230 kV and 500 kV systems to improve transfer capability. The most recent addition, a 138 Mvar bank, was installed on the 500 kV system early in 1987. An additional 138 Mvar capacitor bank is scheduled for installation on the 500 kV system in 1987. During the review period, 158 miles of 500 kV transmission lines and 297 miles of 230 kV lines are planned to be added in the Region.

One major MAAC transmission reinforcement project, the Baltimore-Washington 500 kV loop, is currently in progress. The installation of the Baltimore-Washington 500 kV loop will improve the power system stability in the Baltimore-Washington area and increase the MAAC transfer capability from the adjacent ECAR and SERC Regions. This project was originally scheduled to be completed in the mid-1970's but has been delayed until the early 1990's due to regulatory and judicial proceedings. Approximately 82% of the loop is in service. The Burches Hill-Ox 500 kV interconnection between Potomac Electric Power Company and Virginia Power was placed in service on December 11, 1986. The two seg-

ments of the loop remaining to be completed within MAAC are the Chalk Point-Calvert Cliffs circuit and the Brighton-Waugh Chapel circuit. The certificates for both of these circuits have been received from the Maryland Public Service Commission and the zoning process has begun. Until this loop is completed, the Baltimore-Washington area will be exposed to reduced power system stability margins and lower import capability benefits.

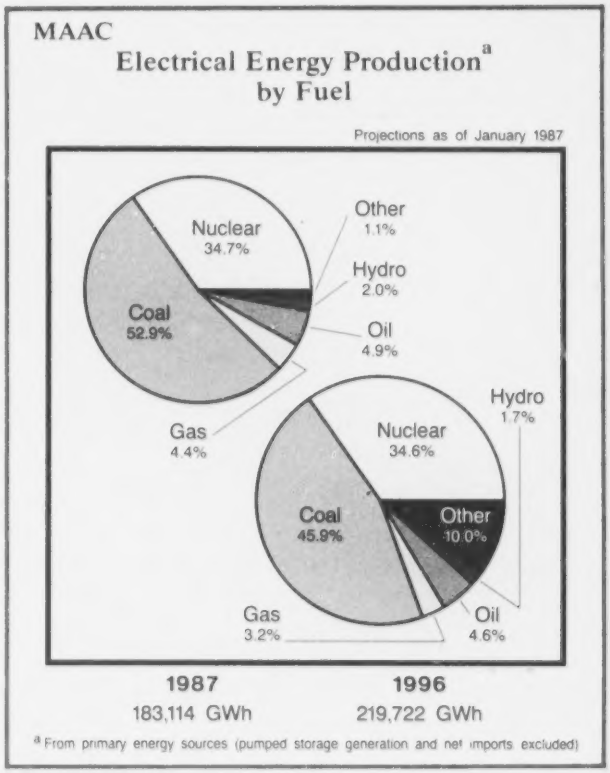
With the transmission system as planned, MAAC's transfer capability within MAAC and from surrounding regional councils is expected to be adequate through 1996.

Operating Issues and Coordination

Although accepted reliability standards are maintained, the MAAC regional bulk electric power system is operated close to its thermal and reactive power limits for a significant portion of the time due to economy energy transfers. MAAC transmission utilization averaged 95.2% during all hours of 1986 based on the flow on the most limiting transmission facilities. The addition of nuclear units in MAAC during 1985 and early 1986, coupled with the declining price differential between coal and oil, has resulted in a reduction of economy energy purchases from systems to the west of MAAC during 1986. MAAC's transmission system, however, is expected to be heavily utilized for economy transfers of low cost generation from central and western portions of MAAC to load centers in eastern MAAC, particularly during daily peak load periods. Recognizing the demonstrated volatility of oil prices, the magnitude of economy energy transfers in the future is highly uncertain. Flexibility must be maintained to respond as conditions change.

The expected heavy use of the MAAC transmission system due to MACC member economy transfers requires close coordination for energy transfers among utilities in regions outside of MAAC. Regardless of the contractual arrangements for transmission service for energy transfers, power will actually flow over all possible parallel paths due to the inherent electrical nature of the transmission network. This phenomenon, known as parallel or loop flow, can cause increases in loading on transmission systems of utilities not party to the transactions. These increased power flows can decrease the reliability of utilities not directly involved in the transactions and can limit their economic benefit from internal energy transfers.

Based on interregional coordinated studies, MAAC and the New York Power Pool of NPCC have reached agreement on what constitutes normal and excess use of each other's transmission systems. The agreement includes an arrangement to purchase and install phase shifters on the Branchburg-Ramapo 500 kV Tie in 1988 in order to control parallel flows.



Other potential sources of significant adverse impact on the MAAC transmission system are disturbances caused by the sudden loss of generation in regions outside of MAAC. The MAAC system is operated such that the more probable disturbances, even those remote to the MAAC system, will not cause thermal overloads or excessive voltage drops in the MAAC system. For example, loss of generating sources in systems north and east of MAAC can cause a significant increase in west-to-east power flow through the MAAC system. Since the MAAC system is operated at its west-to-east transfer limit a large portion of the time, this incremental power flow could adversely affect the reliability of the MAAC system unless interregional operating guidelines are developed. Joint interregional planning and operating studies identify the contingencies of mutual concern, and plans and operating guidelines are developed to alleviate any potential problems. Three current examples of such joint studies follow:

- The impact of Hydro-Quebec exports on MAAC, ECAR and NPCC is the subject of an ongoing joint study by an interregional committee composed of members from MAAC, ECAR, and NPCC (MEN). This ongoing study is a two-part effort. The completed MEN 1990 Study—Part I investigated the maximum allowable Hydro-Quebec exports to New England over

the Des Canton-Comerford-Sandy Pond HVDC Tie, with its expanded 1990 capability of 2,000 MW, as a function of the west-to-east transfer levels in New York (NPCC) and MAAC.

- The MEN 1990 Study—Part II will address reliability issues of the Eastern Interconnection under contingency conditions including the loss of 3,900 MW of Hydro-Quebec exports over HVDC ties to New York, New England and New Brunswick. The effectiveness of a proposed dynamic isolation scheme in the Hydro-Quebec system and other measures being developed to reduce the magnitude and impact of this 3,900 MW contingency will also be assessed.
- Another interregional study investigated the impact of the loss of Hydro-Quebec exports to New York and New England on MAAC in the 1986-1990 period and confirmed that the loss of Hydro-Quebec exports, under certain conditions, could be more restrictive to MAAC transfers than internal MAAC contingencies. This joint interregional planning effort was the impetus that led to an ongoing interregional Operations Study of these issues. The Operations Study has already resulted in implementation of interregional operating guidelines to restrict Hydro-Quebec exports to maintain loadings on transmission facilities within safe operating limits thereby enhancing the reliability and economics of the interconnected systems.

Because power transfers and disturbances can have widespread effects on an Interconnection, extensive coordination of operation among utilities is required. System operators must take into account many operating constraints when making decisions regarding reliable and economic operation of the electric system. Identification and monitoring of these constraints must be broad enough to include system conditions outside of an operator's immediate control area. Coordinated operation must continue in order to maintain safe, reliable, and economic operation of the bulk electric systems as conditions change and new issues arise.

The MAAC Region consists of 11 member systems and 5 associates serving over 20 million people over a 48,700 square mile area. The Region includes all of Delaware and the District of Columbia, major portions of Pennsylvania, New Jersey and Maryland, and a small portion of Virginia.

MAIN

Mid-America Interconnected Network

Adequate capacity is expected to be available for reliable supply to the 1987-1996 projected loads in MAIN. A major concern is the unknown effect of possible regulatory actions related to acid rain. There is also concern about the uncertainty of the effectiveness of future programs related to conservation, load management and non-utility generation.

Actual			Forecast		
	Summer	1986	1987	1996	Growth Rate
	Winter	1986/87	1987/88	1996/97	(%/year)
Summer Peak—MW		35,943	36,380	41,883	1.6
Winter Peak—MW		28,036	29,469	34,878	1.9
Annual Energy—GWh		177,190	179,198	211,089	1.8
Installed Capability (summer)—MW		45,351	48,362	50,042	0.4

Demand and Energy

The 1986 summer peak demand in MAIN was a new all-time high and was 10.8% above that of 1985 and 0.5% above the forecast. The 1986 demand was 3.1% above the previous peak of 34,858 MW in 1984.

Energy use in MAIN increased by 2.1% over 1985 and was slighily over forecast. The increased energy use is attributed to some improvement in the economy of the Region and to more normal weather conditions.

During the 10-year period 1987-96, summer peak demand is forecast to increase at an average annual rate of 1.6%. The annual energy use is forecast to grow at 1.8%. There is little change from last year's estimate for specific future years. For example, the current forecast for 1995 is only slightly higher than that made last year for 1995.

In general, the planned use of load management and non-utility generation in MAIN in 1987 is relatively modest compared to some other regions. Non-utility generation is estimated to constitute 1.1% of the installed capacity in 1987 and is projected to increase to 1.8% by 1996. Corresponding estimates of the effect of directly controlled load management are 2.2% of peak load in 1987 and 2.5% of the projected peak load for 1996.

Generation Resources

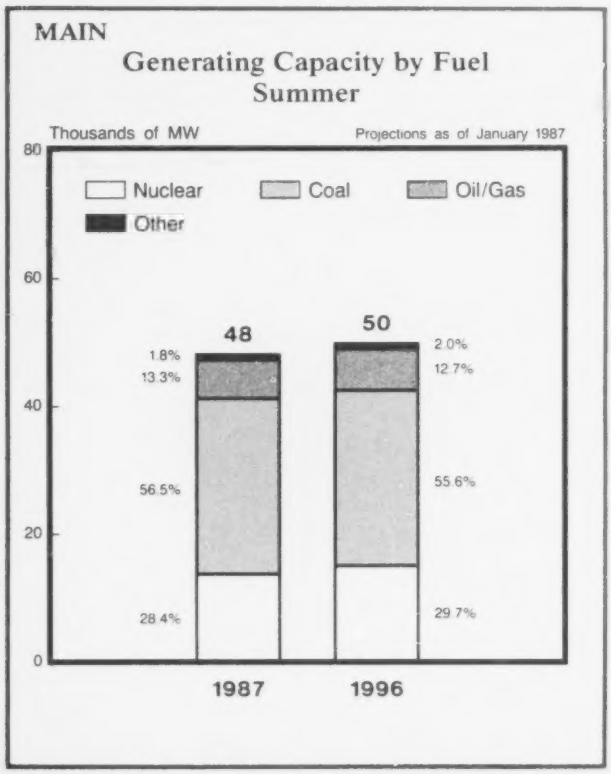
Generating capacity in MAIN is predominately coal and nuclear. In 1987, about 59% of the electric energy is expected to be produced from coal and about 39% from nuclear. Corresponding estimates for 1996 are 55% from coal and 42% from nuclear.

Four new nuclear units with a total capacity of 4,310 MW are expected to be placed in commercial operation in 1987 and 1988. Clinton 1 (950 MW), Byron 2 (1,120 MW) and Braidwood 1 (1,120 MW) are scheduled for 1987. The fourth unit, Braidwood 2 (1,120 MW), is scheduled for 1988.

With these four new units, generating capacity scheduled for 1996 will be adequate for reliable supply to the projected peak demand. No major additional units are now planned for service during the 1989-1996 period.

The generating reserve criterion used in MAIN provides that the utilities should maintain installed capacity at least 15 to 20% above the forecast peak load in each year. This is equivalent to a capacity margin of 13 to 17%. The reserve criterion was reviewed in 1986 and was determined to continue to be applicable for conditions expected in MAIN during the forecast period.

The planned capacity is above the required minimum to supply the demands projected through the 10-year period 1987-1996. Margins will be well above minimum for several years with the new nuclear capacity scheduled for 1987 and 1988 in service. This situation will enhance reliability and will facilitate scheduling of maintenance. The availability of low cost coal and nuclear generation will provide opportunities for economy transfers and for possible sales to other areas. A capacity margin of 18% is projected for 1996. If loads grow faster than now projected, additional capacity will be required in the mid-1990's. For example, annual peak demand growth of 2.3% (compared to the projected 1.6%) would result in a 13% capacity margin by 1996.



Future Issues Influencing Adequacy

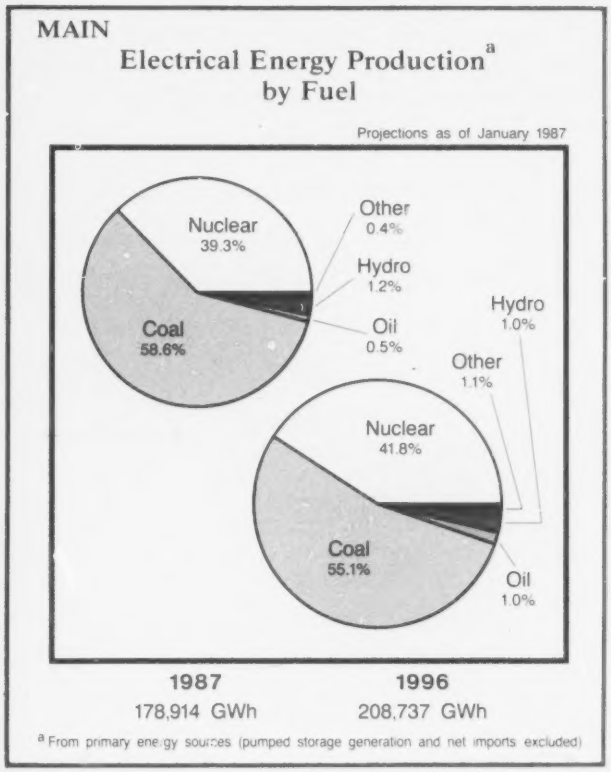
The most critical concern in MAIN is the possible impact of future regulatory actions dealing with acid rain. Since coal is the major fuel in MAIN, new requirements for reduced sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emissions may adversely affect reliability of supply. The maximum net output of existing coal units would be reduced if retrofitted with emissions control facilities. The average availability of retrofitted units may also decrease. It may not be possible or economic to retrofit some older units thus causing premature retirement. These factors would tend to reduce the capacity available from existing coal units with the result that new replacement capacity will be required. If new regulations are developed to control acid rain, the cost and lead time for the required replacement capacity must be given suitable consideration.

As a positive step toward emission reduction, the Wisconsin Electric Power Company has proposed conversion of 4 pulverized coal boilers (500 MW) in its Oak Creek power plant to atmospheric fluidized bed combustion.

Another concern is the possibility that future peak demand may be greater than forecast. Utilities and regulatory agencies are placing greater emphasis on programs to encourage conservation, load management and non-utility generation. Some of the MAIN utilities have based their need for new capacity on assumptions about the future success of these programs. The degree of success of these programs (which is difficult to predict) will affect the need for new generating capacity. That is, these new programs add one more uncertainty into the forecasting process. MAIN load forecasts are intended to have an equal probability of being high or low. The effects on reliability, however, are far from equal for actual peak demands higher or lower than forecast. The present difficulty for utilities to site, license, finance and construct new generating capacity in a timely manner results in a greater risk to reliability if actual loads turn out to be greater than forecast. If load forecasts turn out to be too high, there may be substantial economic impact, but reliability would not be jeopardized.

Transmission

The transmission system in MAIN is adequate for reliable operation for both internal transfers and those involving adjoining regions. Studies are conducted on a



regular basis to assure that transmission capacity will continue to be adequate. These include near-term operating studies, longer-term studies of interchange capability, and extreme disturbance studies. Each of these studies includes participation by representatives from other regions to provide interregional coordination.

In addition, MAIN participates in two interregional reliability coordination agreements. One includes MAIN, ECAR, and the TVA Subregion of SERC. The other includes MAIN, MAPP, and SPP. These agreements provide for periodic review of the adequacy and security of the interregional systems.

Transmission loading approached allowable limits (First Contingency Incremental Transfer Capability or FCITC) in some areas for a relatively small part of 1986. One area of concern involves power transfer from MAPP to MAIN. Economy transfers have occasionally been limited in order to ensure secure operation. Another area being watched closely is the Joppa-Shawnee-Paducah area which, in the past and prior to system modifications, has limited TVA's import capability from MAIN. There are no situations which are judged to jeopardize reliable operation.

There were no major problems related to delay of transmission scheduled for 1986. During 1986, one 345 kV line (Byron-Cherry Valley—22 miles) was placed in service as scheduled.

Relatively modest transmission reinforcement is scheduled for service in the next few years. Two new 345 kV lines from MAIN to MAPP (Quad Cities-Rock Creek and Quad Cities-Sub 91) are scheduled for service in 1987 and 1988. These new lines are primarily intended to provide local system reinforcement. New 345 kV lines are scheduled for 1988 to deliver the output from the new generating unit, Braidwood 2. Two new 345 kV lines in southern Illinois (W. Frankfort-Norris City and Norris City-Albion) are scheduled for 1989 and 1990.

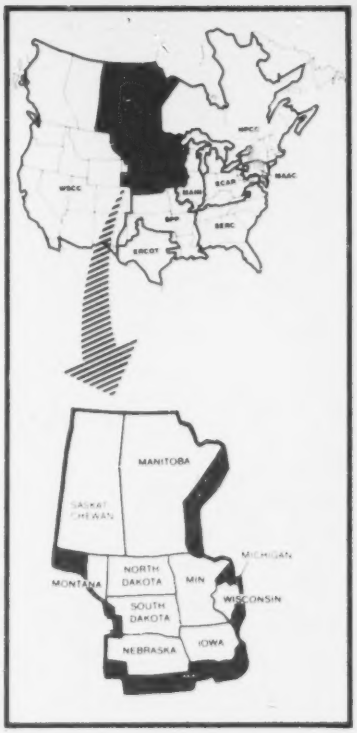
Operations

Utilities are taking steps to assure reliable operation by providing additional monitoring capability and by increasing operator preparedness. A new computer facility has been installed at the MAIN Coordination Center to improve the effectiveness of monitoring the bulk electric system. This is the first step in the eventual replacement of the communication system that was installed in 1980. Through daily reports on the communication system, information is broadcast to MAIN companies and surrounding regions on expected daily loads and capacity margins and on unit and transmission status changes and scheduled outages. In addition, work is underway to improve individual system control centers, to provide operators with more and better information on the current state of the electric system, and to provide for continued and more extensive operator training.

The Mid-America Interconnected Network (MAIN) consists of 13 regular member systems and 1 associate member. MAIN is a summer peaking Region containing Illinois, the eastern third of Missouri, the eastern two-thirds of Wisconsin and most of the Upper Peninsula of Michigan.

MAPP

Mid-Continent Area Power Pool



The MAPP Region projects adequate transmission and generation capabilities to meet the forecasted load requirements reliably throughout the 1987-1996 review period. The capacity margin is projected to decline from 29.6% in 1987 to 25.4% by 1996, and should be adequate for the assessment period.

Actual		Forecast		
Summer	1986	1987	1996	Growth Rate
Winter	1986/87	1987/88	1996/97	(%/year)
MAPP — U.S.				
Summer Peak—MW	21,039	21,645	24,949	1.6
Winter Peak—MW	18,850	19,310	22,323	1.6
Annual Energy—GWh	106,824	111,280	130,316	1.8
Installed Capability (summer)—MW	28,438	28,772	30,146	0.5
MAPP — Canada				
Summer Peak—MW	3,896	4,099	5,518	3.4
Winter Peak—MW	5,243	5,499	7,199	3.0
Annual Energy—GWh	27,109	28,094	36,995	3.1
Installed Capability (winter)—MW	6,625	6,606	8,633	3.0
MAPP — Total				
Summer Peak—MW	24,935	25,744	30,467	1.9
Winter Peak—MW	24,093	24,809	29,522	2.0
Annual Energy—GWh	133,933	139,374	167,311	2.1
Installed Capability (summer)—MW	35,054	35,398	38,775	1.0

Demand and Energy Projections

The MAPP demand and energy forecasts are the sum of the individual MAPP member forecasts. Summer peak demand and annual energy of MAPP are projected to increase at an annual average rate of 1.9% and 2.1%, respectively, for the 1987-1996 period. These projections are slightly reduced from the previous year's projections and indicate almost the same summer peak demand and annual energy projection as last year, but delayed by one year. The MAPP area continues to experience a depressed farm and steel industry economy.

The United States portion of the MAPP Region is summer peaking and experienced a non-coincident peak of 21,039 MW in 1986. This peak demand was 5.5% above

the 1985 peak and 2.3% below the 1986 forecast. The 1986 MAPP-U.S. energy requirements were 1% greater than 1985, but 1.9% less than forecast. The Canadian provinces, which are associated with MAPP, are winter peaking and had a non-coincident peak demand of 5,243 MW in 1986/87 winter season. This peak demand exceeded the 1985/86 winter peak by 5.9% but was 5.5% below forecast. The 1986 energy requirements were 1.4% greater than 1985, but 1.6% less than forecast.

MAPP utilities are actively pursuing various load management programs to reduce growth in peak demands. Utilities expect, by 1996, to be able to reduce peak demands by 1,000 MW through direct control of customer loads.

Capacity Resource Additions

One new generating unit, a 450 MW lignite unit in North Dakota, was placed in service in 1986. The MAPP-U.S. coal-fired capacity for the 10-year assessment period is projected to increase by an additional 2,073 MW. These coal additions include an 850 MW unit scheduled for service in 1987, a 500 MW unit in 1996, and approximately 610 MW of coal-fired units anticipated to be brought back into service from mothball status by 1996. The remaining coal capacity increase involves upratings of existing coal units.

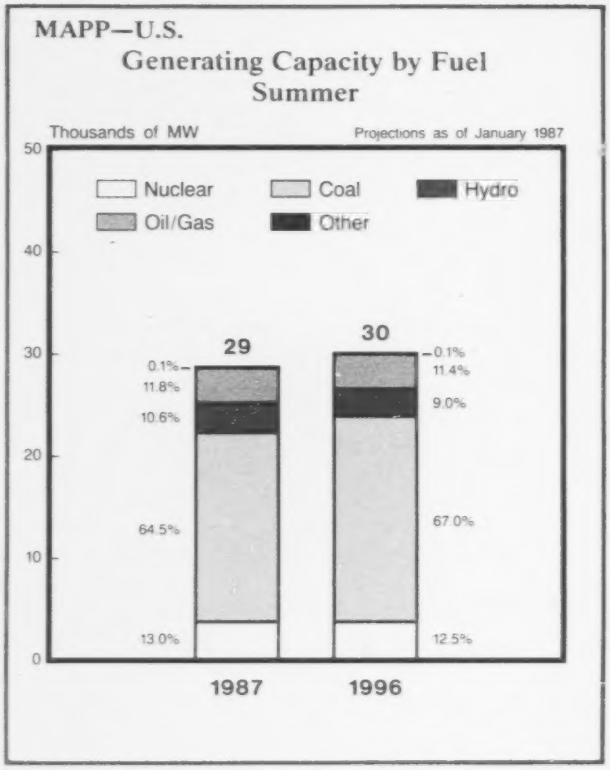
The Canadian provinces of Manitoba and Saskatchewan which are associated with MAPP project the addition of 1,292 MW of hydro capacity by 1994, 560 MW of coal-fired capacity by 1996, and 295 MW of combustion turbines over the forecast period. The installed capacity for the two Provinces will increase from 6,625 MW in 1986 to 8,633 MW by 1996.

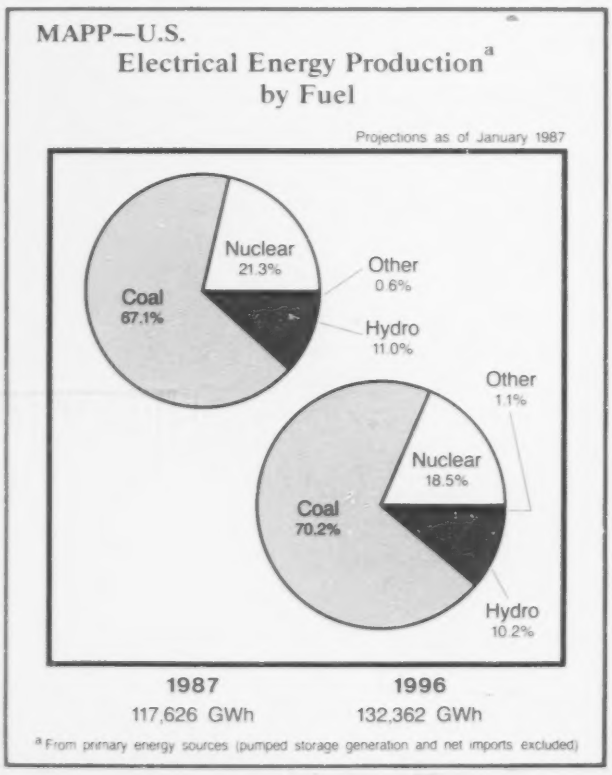
Since 1984, to better utilize existing capacity resources, various MAPP utilities have either sold or purchased interests in existing generating facilities within MAPP. Such capacity ownership changes to date have amounted to approximately 400 MW. Because of seasonal peak diversities, long-term agreements have also been made among MAPP utilities to exchange capacity seasonally.

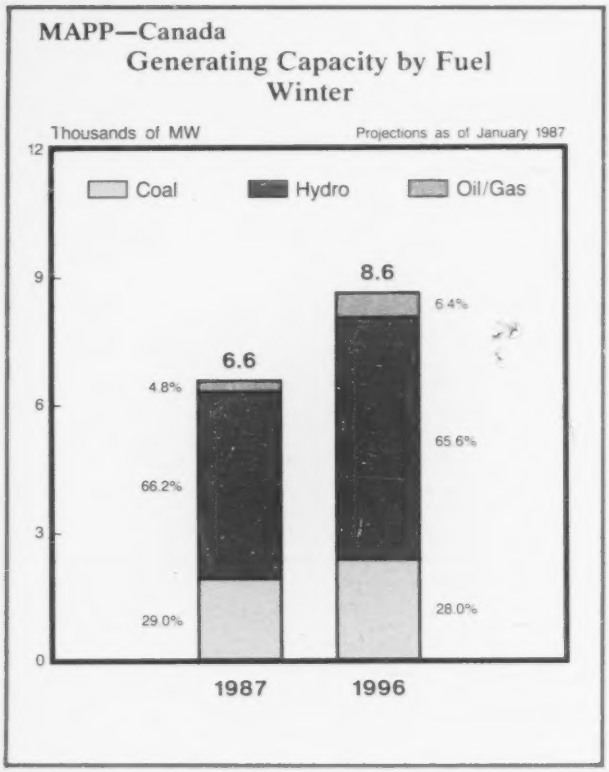
Through the purchases of capacity in existing units and the exchange of capacity on a seasonal basis, installation of nearly 1,000 MW of new capacity has been avoided in MAPP.

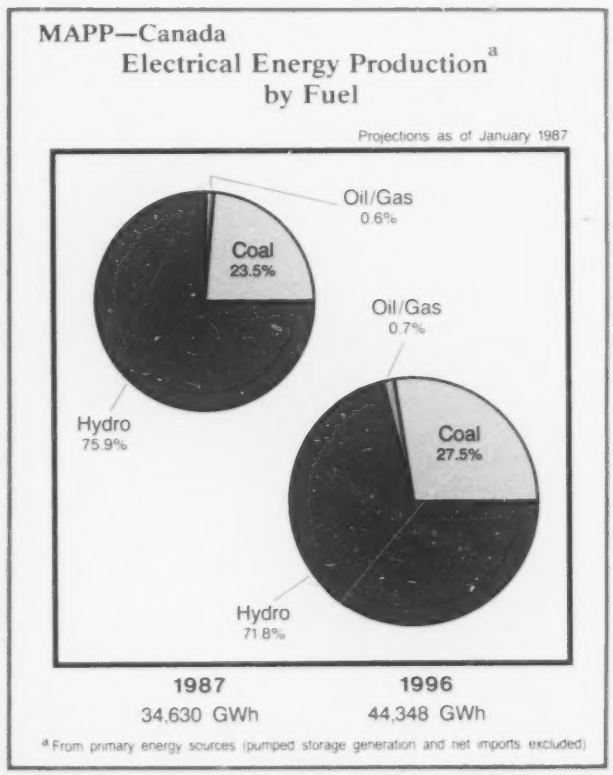
Transmission Additions

The MAPP utilities have 19,948 miles of ac and dc transmission lines 230 kV through 500 kV in service. Over the next 10 years, transmission plans call for the construction of 1,945 miles of 230 kV through 500 kV lines. Transmission facilities as planned are judged to be adequate throughout the 10-year review period.









Electrical Energy Production

The electrical energy production from coal in MAPP is projected to increase from 57.2% in 1987 to 59.5% in 1996. The portion of electrical energy from hydro capacity will range from 25.8% in 1987 to 25.7% in 1996, while the nuclear electrical energy production share will decrease from 16.4% to 13.9%. Over this 1987-1996 period, the use of oil and gas is projected to contribute less than 1% of MAPP's electrical generation. Similar figures for the 1987-1996 forecast for MAPP-U.S. and MAPP-Canada are shown in adjacent figures.

System Operations

MAPP experienced two unique failures of large generating facilities in 1986. In September, Neal 4, a 550 MW coal plant located in western Iowa, was hit by a tornado. The coal handling system was totally destroyed and the plant was out of service for nine months. Coal Creek 2, a 550 MW unit in western North Dakota, was totally disabled from a boiler explosion while under full load operation. Upon replacement of the major portion of the boiler and structural steel, the unit is scheduled to return to service in December 1987. Neither of these unit failures caused electrical interruptions to customers and the integrity of the bulk electric system was maintained.

By means of the MAPP computerized telecommunications network, the utilities are routinely informed on generation and transmission status, capacity resource availability, needs, and prices. Through use of this information network, MAPP utilities have the ability to make transmission network energy transactions among adjacent and non-adjacent utilities. This has resulted in a substantial increase of economic energy transfers within the Region.

MAPP utility operators utilize regional and interregional economy energy transfers to optimize energy costs. In 1985, 45% of the MAPP energy supply was provided through economic energy transfers within the Region.

Regional and Interregional Coordination

MAPP presently is developing a Long-Range 20-Year Generation and Transmission Study on a regional basis. This regional planning effort is proposed to be completed in 1988. It will identify the mix of supply side and demand side options which will be required to meet projected load requirements in MAPP for the next 20 years.

An intraregional study among Manitoba Hydro and various Minnesota-Iowa utilities has been completed. Negotiations for a long-term purchase from Manitoba Hydro of 550 MW of capacity and 500 MW of seasonal diversity exchange are presently being pursued for initia-

tion in the late 1990's for a period of 15 years. Transmission additions at 345 kV and 500 kV are also proposed to accommodate these transactions.

Along with MAIN and SPP, MAPP concluded interregional screening studies in 1986 to evaluate the interregional potential for economy energy transfers among the three regions for the period 1986-1995. These joint studies identified potential economic energy transfers among the regions and have provided the regional utilities a basis for identifying economic potentials of such economy energy transfers in the future.

In 1986, MAPP and MAIN collaborated on the development of a common format for the collection of bulk transmission outage data. This data continues to enhance the projected probabilities of outages used in the Region's future reliability assessments.

Regional and interregional coordination is also evidenced by the heavy utilization of various transmission interconnections for the sale and purchase of economy and emergency energy. For example, transmission capacity has been utilized at capacity factor levels equivalent to baseload generation in MAPP. The regional transfer capacity of 1,450 MW between MAPP-U.S. and MAPP-Canada during the summer season of 1986 was utilized at a level of 70.8%. Interregional energy transfer capacity between MAPP and WSCC for 1986 was used to 86.8% of its maximum capability. These levels are based on 8,760 hours per year, without allowing for maintenance outage periods.

Interregional energy transfers of MAPP to MAIN and SPP have been increasing annually since 1976. The recently completed MAPP-MAIN-SPP studies indicate continued growth of these interregional transfers for 1987-1996. Further interregional transfer capacity between MAPP and WSCC will be possible by the addition of a fourth dc intertie being constructed by the Canadian provinces of Alberta and Saskatchewan. The 100 MW to 150 MW tie is scheduled for 1989 completion.

Reliability Issues

Legislative efforts to further reduce emissions of sulfur dioxide and nitrogen oxide from coal-fired power plants increases the uncertainty of the adequacy of the MAPP coal-fired generation capacity. Potentially, the available power from MAPP's coal units could be reduced, could be less reliable because of the added complexity of emission control facilities, and may be required to be removed from service for an extended period of time for retrofitting. Thus, the potential changes in emission standards create uncertainty as to the adequacy of a major portion of the capacity resources in MAPP.

Trends in MAPP are to creatively increase utilization of the present capacity resources through seasonal diversity exchange agreements and to expand regional - and interregional energy transfer through greater utilization of the transmission network. Such trends of greater utilization, however, reduce the reliability margins of the systems and the need for assessments becomes more critical. Further, greater dependency on the coordination and planning among the utilities becomes paramount to maintain reliability standards.

There is great uncertainty with respect to MAPP's direct control load management programs. Customer acceptance has been favorable for those MAPP utilities that have pursued load management programs, but the actual frequency of customer interruptions has been only 1-2% of the frequency that may be required in the future. Customer acceptance over the long-term and the amount of load available to be interrupted remain uncertain. The potential for unanticipated load exists and poses a threat of rapid capacity margin reduction should the customer with managed load find interruption of service unacceptable.

Reliability Assessment

The capacity margins for the summer peak periods in MAPP-U.S. are projected to decrease from 27.2% in 1987 to 22.0% in 1996. Similarly, the capacity margins for the winter peak periods in MAPP-Canada are projected to decrease from 18.8% to 18.2% over the forecast period. Although the capacity margins will decrease, they will continue to meet MAPP reliability criteria and therefore should be adequate over the assessment period.

The Mid-Continent Area Power Pool (MAPP) membership includes 43 systems. There are 27 participants consisting of 11 investor-owned systems, 8 generation and transmission cooperatives, 3 public power districts, 4 municipal systems, and 1 Federal agency. The associate participants consist of 2 Canadian Crown Corporations, 13 municipals, and 1 investor-owned system. The MAPP Region covers all of the states of Iowa, Minnesota, Nebraska, and North Dakota; portions of the states of Illinois, Michigan, Montana, South Dakota, and Wisconsin; and the provinces of Manitoba and Saskatchewan. Total geographic area served is 890,000 square miles with a population of 15.6 million.

NPCC

Northeast Power Coordinating Council

Supply adequacy over the next ten years in the New England and New York Areas of NPCC will depend on the combined contributions of: capacity from utility-owned generating units now complete, nearing completion or planned; load reduction from utilities' conservation and load management programs; deferred capacity retirements from generating unit life extension programs; and non-utility generating capacity. Adequacy will be equally dependent on electric demand growing at a rate not significantly higher than presently forecast. If adequacy problems develop, decisions will be required to purchase capacity or install short lead time generation. Reliability is expected to be acceptable in the Ontario, Quebec, and Maritime (New Brunswick and Nova Scotia) Areas.

Actual		Forecast		
Summer	1986	1987	1996	Growth Rate
Winter	1986/87	1987/88	1996/97	(%/yr)
NPCC — U.S.				
Summer Peak—MW	39,026	41,367	47,447	1.5
Winter Peak—MW	37,976	40,129	44,942	1.3
Annual Energy—GWh	227,865	231,953	268,234	1.6
Installed Capability (summer)—MW	51,879	51,996	56,723	1.0
NPCC — Canada				
Summer Peak—MW	33,508	35,000	43,965	2.6
Winter Peak—MW	47,285	49,614	62,075	2.5
Annual Energy—GWh	256,798	268,982	345,212	2.8
Installed Capability (winter)—MW	57,795	59,424	67,831	1.5
NPCC — Total				
Summer Peak—MW	72,534	76,367	91,412	2.0
Winter Peak—MW	85,161	89,743	107,017	2.0
Annual Energy—GWh	484,663	500,935	613,446	2.3
Installed Capability (winter)—MW	111,213	116,436	126,186	0.9

Peak Demand and Energy Forecast

The consumption of electric energy increased in all five Areas of NPCC between 1985 and 1986, exceeding forecasts in each Area as well. Among U.S. members, electric energy use increased by 3.2% while Canadian members witnessed a growth of 4.0%.

Aggregated 1986 summer peak demands of the U.S. members of NPCC were down slightly as compared to 1985. In Canada, the 1986/87 aggregated winter peak demands were up over 1985/86. However, short-term peak demand comparisons are not a good index of trends, since such comparisons can be significantly influenced by weather variations.

A comparison of 1986 and 1987 long-term NPCC forecasts for peak demand and energy is given in the following table:

Forecast Average Annual Increase Over the Next 10 Years (%/Yr)		
	1986 Forecast	1987 Forecast
Peak Demand—NPCC/U.S.	1.7	1.5
Peak Demand—NPCC/Canada	2.9	2.5
Annual Energy—NPCC/U.S.	1.9	1.6
Annual Energy—NPCC/Canada	3.2	2.8

The 1987 forecast represents an average growth in peak demand for all of NPCC of about 2,000 MW per year.

The general reduction in forecast growth rates reflects, among other things, increased application of demand management programs, as discussed in the next section.

Demand Management

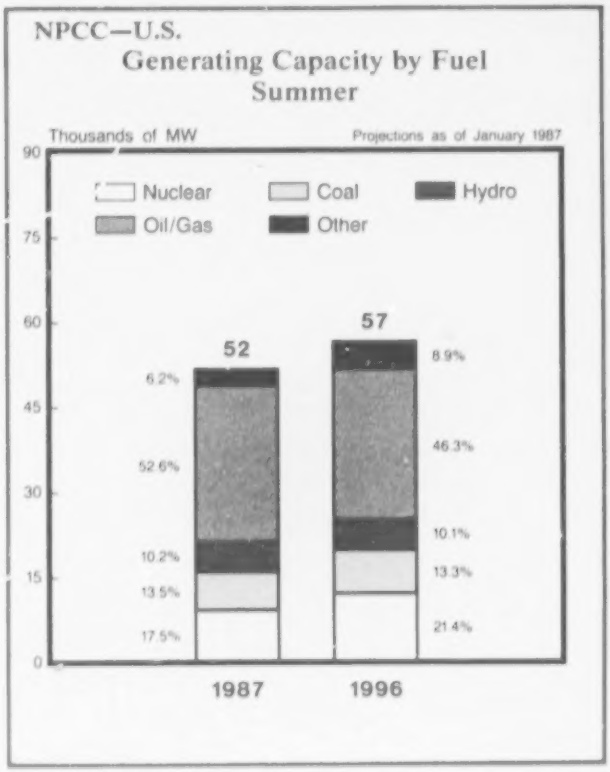
Many NPCC member systems are committed to pursuing cost-effective demand management programs. Such programs have increased significantly over the past several years.

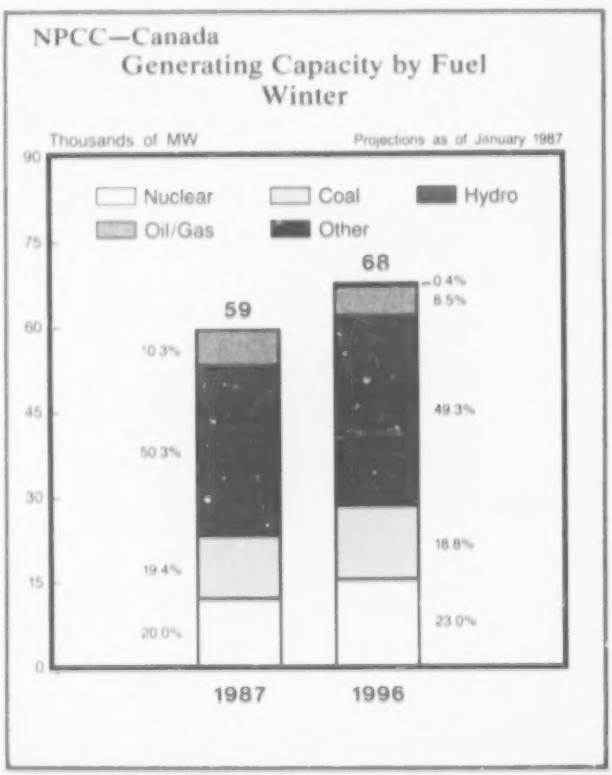
In the New England Power Pool (NEPOOL), the reduction in peak load through demand side management is expected to reach approximately 1,400 MW by 1996. This is equivalent to about 7% of the summer peak demand, and is expected to reduce annual energy requirements by about 3%. Of the 1,400 MW, about 30% will be active load management under the control of the system operator.

The New York Power Pool (NYPP) peak demand forecast includes the effect of market-induced load management programs that will reduce the forecast growth in peak load by 1,900 MW through 2003, or about 25% of what the growth would be in their absence. In addition, but not subtracted from the NYPP forecast, are approximately 1,000 MW of potentially cost effective utility-induced demand side options, which may be achievable through 2003.

Ontario Hydro (OH) projects about 2,000 MW of demand management by 1996, including efficiency improvements, load shifting and interruptible loads, representing about 8% of winter peak demand. About one-third will be under dispatcher control. The demand side management programs are expected to reduce total annual energy consumption by approximately 1.6%.

Demand management currently accounts for approximately 2,000 MW or about 8% of Hydro-Quebec's winter peak demand. Hydro-Quebec expects in the next 10 years





to add another 2,000 MW of demand management by increasing its interruptible load and by automatically controlling dual energy systems. By 1996, demand management will account for 12% of the winter peak demand. The total effect on annual energy requirements is expected to be about a 0.4% reduction.

In the Maritime Area of NPCC (New Brunswick and Nova Scotia), there currently exists about 100 MW of interruptible and non-firm load which is included in the peak demand forecast. Although research on demand management is being carried out, no alternatives to date have been found cost effective.

Supply

The only major utility-owned capacity addition scheduled for service over the next 10 years in New England is Seabrook 1 (1,150 MW nuclear). A year ago, Seabrook was scheduled for service November 1, 1986. Largely because of regulatory delay, its service date is now November 1, 1987. Committed capacity purchases from outside New England will total about 200 MW by 1996. In addition, the interconnection capacity equivalent of the Hydro-Quebec firm energy contracts equals 1,500 MW. Non-utility generators are projected to contribute some 1,200 MW of capacity by 1996. About 1,000 MW of additional non-utility generation is as yet uncommitted (i.e., planned but neither under construction nor licensed), and hence is not included as capacity.

In addition, a letter of intent has been signed between Hydro-Quebec and Central Maine Power Company for 400 MW of capacity beginning in 1992, increasing to 600 MW in 1995, and to 900 MW in the year 2000. This arrangement is not yet firm, however, nor has it been reviewed by NPCC.

In New York, the Shoreham nuclear unit (809 MW), 100% complete for more than 2 years, is now scheduled for service in early 1988; low power tests (5%) were successfully conducted in October 1985. In the past year, Nine Mile Point 2 (1,080 MW nuclear) has been delayed from January 1987 to early 1988. The Niagara expansion project, a 300 MW hydro peaking installation, has been delayed from May 1994 to May 1995. The Prattsville 1,000 MW pumped storage project, long delayed by environmental issues, has now been canceled. A 170 MW combined cycle installation at Lovett is planned for April 1996. Capacity imports from Hydro-Quebec will equal 800 MW for each summer peak period over the next 10 years. NYPP will also rely on life extension and non-utility generation, which are expected to add about 1,500 MW and 1,100 MW respectively by 1996.

Five nuclear units in the 800 to 900 MW range are scheduled for service in Ontario between 1987 and 1992. Along with a number of nuclear upratings, these will add 4,500 MW of capacity to the system. The units are Bruce B 8, which went into service in May 1987, and Darlington 2, 1, 3 and 4 (November 1988, August 1989, May 1991 and February 1992, respectively). Non-utility generating capacity is projected to increase by approximately 200 MW, although none of this has yet been constructed or licensed. About 500 MW of new hydroelectric generation is in the planning stage for service between 1993 and 1995. However, it has not yet been committed for construction.

For Hydro-Quebec, those units scheduled for service by 1996 include 4,140 MW of hydro peaking capacity of which 3,140 MW is already committed (Manic 5 AC 980 MW in 1989, LG 2A 1,900 MW in 1992-93, and 260 MW of miscellaneous water wheel replacement). The remaining 1,000 MW consists of hydro peaking capacity and water wheel replacement which are under study for a potential in-service date of 1995-96. In addition, there is 2,500 MW of hydro baseload generation (La Grande Complex Phase II — 13.8 TWh/year) ready to be committed for an in-service date in the mid-1990's if a need arises.

New coal-fired capacity of 600 MW is planned for service by 1996 in Nova Scotia. In New Brunswick, 200 to 400 MW of new thermal capacity is planned to be in service in the early 1990's.

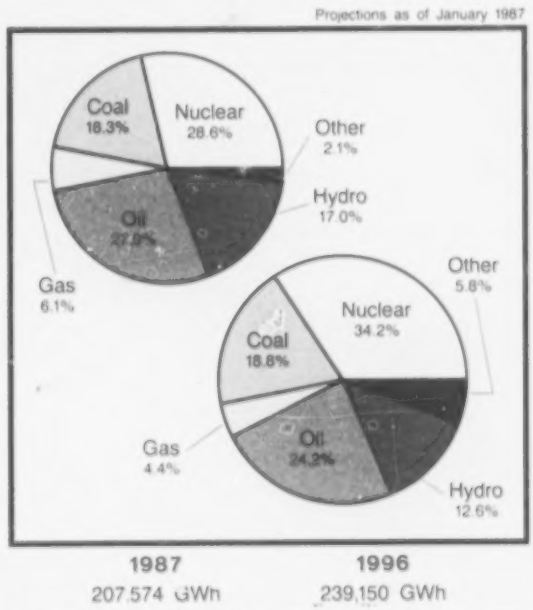
Although major reductions in the use of oil have been realized in recent years, NPCC (U.S.) remains the most oil dependent region in NERC. Oil-fired generation represents about one-half of total New York and New England generating capacity over the assessment period. As a percent of total electrical energy production, oil is projected to provide 28% of total requirements in 1987 and 24% in 1996. Continued availability of adequate supplies of oil for electric generation thus remains a concern in NPCC.

Assessment of Adequacy

In general, projected resources in NPCC are expected to be adequate to supply peak demand and annual energy requirements through the ten-year period. However, supply adequacy among U.S. members will depend on the success of demand management programs and on the installation of non-utility generation. Already, portions of the capacity programs of the utilities are in question — e.g., the completed Shoreham unit and the nearly completed Seabrook unit. If demand management programs prove less successful than anticipated, or if non-utility or utility-owned generation does not meet projections, an inadequate balance of capacity resources vs. load could quickly develop.

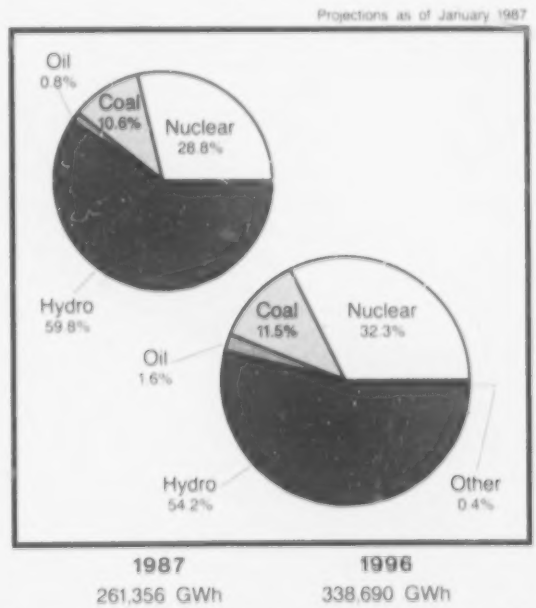
Future adequacy is equally dependent on electric load growing at a rate not significantly higher than presently forecast. The combined New England and New York fore-

NPCC—U.S.
Electrical Energy Production[a]
by Fuel



[a] From primary energy sources (pumped storage generation and net imports excluded)

NPCC—Canada
Electrical Energy Production[a]
by Fuel



[a] From primary energy sources (pumped storage generation and net imports excluded)

cast aggregation for 1987 projects an annual energy growth rate of 1.6% from 1987 through 1996. It is notable that, during the period of strong economic growth from 1982 through 1986, combined New England and New York energy grew at about twice that rate. Should future demand and energy growth rates exceed current forecasts, adequacy problems could develop even if all planned utility generation, non-utility generation, and demand management programs are successful.

If adequacy problems do develop, decisions will be required to purchase capacity or install short lead time generation.

Transmission

Several major bulk power transmission projects are underway in NPCC. Phase I of the Hydro-Quebec (HQ)-NEPOOL interconnection was placed in service in October 1986. A ±450 kV HVDC line now runs from Des Cantons in Quebec to Comerford in northern New Hampshire, and is capable of transferring up to 690 MW. An operations study jointly conducted by the NYPP, NEPOOL and Pennsylvania-New Jersey-Maryland (PJM) power pools determined the mutual interactions among power flows on the ac systems of PJM and NYPP and the power flows on the five HVDC ties between Hydro-Quebec and the other NPCC systems. As a result of this study, operating procedures have been established to prevent unacceptable loading, voltage, or stability conditions for the simultaneous loss of all HVDC ties or an outage of the entire Hydro-Quebec system.

By 1990, the planned extension of the Des Cantons-Comerford HVDC line north to Radisson near James Bay and south to Sandy Pond in eastern Massachusetts will increase the capability of the tie to 2,000 MW. A joint MAAC-ECAR-NPCC (MEN) 1990 study is investigating the potential effects of this Phase II interconnection on systems to the west and south. The first part of this study, dealing with contingency loss of the HQ-NEPOOL tie itself, has now been completed. Allowable flows on the HQ-NEPOOL tie as a function of west-to-east transfers in PJM and NYPP, and vice versa, have been established such that loss of the tie will not be more severe than individual single contingencies within PJM or NYPP. The second part of the study, now in progress, is investigating stability and the effects of the loss of the Hydro-Quebec system.

Hydro-Quebec proposes to adopt new criteria which are intended to minimize the occurrence of a complete Hydro-Quebec system shutdown, unacceptable loss of multiple HVDC interconnections, and to alleviate the need for generation isolation for future interconnections. An NPCC working group is assessing the impact on other NPCC Areas and the overall interconnected network.

Construction of the 200-mile 345 kV Marcy-South reinforcement between central and southeastern New York is progressing, and some sections are already in service. This reinforcement, which is scheduled to be completed in 1988, will permit increased displacement of oil-fired generation in southeastern New York by more economical generation in upstate New York, Ontario and Quebec. Also, reliability in New York will be improved.

A 345 kV cable reinforcement between Sprain Brook in Westchester County, New York, and Shore Road Substation on Long Island is planned for service during the winter of 1991/92. This tie is needed to maintain the reliability of the Long Island system as the load grows, and is actually needed today with the Shoreham unit not permitted to operate.

Ontario government approval has been obtained for the Ontario Hydro 500 kV transmission lines required to integrate the Bruce nuclear generation complex on Lake Huron into the bulk electric power system. Extensive regulatory delays have necessitated the use of special protection systems until the new lines are in service. The transmission lines in question are also needed to supply the increasing loads in southwestern Ontario and to maintain transfer capability between Ontario and Michigan.

Power flows have increased dramatically on many portions of the bulk electric power transmission system in NPCC over the past ten years; e.g., west to east and north to south in New York, north to south in New England. These increases are primarily due to fuel price differentials, the need to locate generating resources farther from urban load centers, and the growing reliance of systems in New England and New York on generating resources in Quebec. The outlook is for such heavy flows to increase in the future.

Intraregional Coordination

NPCC conducts its business through a series of committees, task forces, working groups, and a full-time staff. Reporting to the Executive Committee are a System Design Coordinating Committee and an Operating Procedure Coordinating Committee, which function collectively as the Joint Coordinating Committees. A Public Information Committee also reports to the Executive Committee. Eight permanent task forces report to the Joint Coordinating Committees, covering the spectrum of the Council's technical activities — Task Forces on Coordination of Planning, System Studies, System Protection, Environmental Matters, Load and Capacity, Coordination of Operation, On-Line Computers, and Fuels. Working groups are established by the task forces when and as needed to perform specific studies or other activities.

The Council has established a series of *Criteria* which define minimum planning and operating criteria for member systems functioning as part of the bulk electric power interconnected network, *Guides or Guidelines* for the achievement of acceptable system performance which implement criteria, and *Procedures* which provide for uniform implementation, interpretation and monitoring of conformance with the general criteria, guides and reporting requirements. There are 30 such documents at present.

The conduct and schedules of the various activities of the task forces and their working groups are monitored and specified by the NPCC Reliability Assessment Program. Special studies not directly specified by the Reliability Assessment Program are conducted when a need arises.

Interregional Coordination

A series of inter-pool coordination agreements exists among the various Areas of NPCC and with neighboring systems; for example, between NYPP and PJM. Studies are conducted by the participating groups as required.

In addition, NPCC is a party to Inter-Area Coordination Agreements established in 1968 with both MAAC and ECAR. Under the terms of these and a three-party agreement among MAAC, ECAR and the VACAR Subregion of SERC, a permanent Joint Interregional Review Committee was established with membership from ECAR, MAAC, NPCC and VACAR. Under this group are the MAAC-ECAR-NPCC (MEN) Study Committee and the VACAR-ECAR-MAAC (VEM) Study Committee. The two Study Committees conduct both long- and short-term load flow and stability analyses on a regular basis—as, for example, the already cited MEN 1990 study on the potential effects of the planned 2,000 MW tie between Hydro-Quebec and New England.

Operations-Specific Coordination

Given the strong intersystem interactions — high capacity, high voltage transmission lines; large, long distance electric power transfers; the potential for widespread system effects — which characterize today's electric power systems, the need for effective operations coordination has never been greater.

Within NPCC, coordination in operations is achieved on a hierarchical basis. At the regional level, criteria, guides and procedures are established and conformance monitored — as described in the Intraregional Coordination section above. More detailed criteria, guides and procedures are developed at the Area level. It is at this level, too, that real-time control of the system begins. Each of the two U.S. power pools and four Canadian systems operates its own control center, where overall system con-

trol and economic dispatch functions are carried out. In NEPOOL, control proceeds from the New England Power Exchange (NEPEX) dispatch center to satellite centers, and then to the individual member systems. In NYPP, control is from the NYPP dispatch center directly to the utility control rooms.

Both voice and telecommunication systems link the NEPEX, NYPP, and Canadian control centers with each other, and also with neighboring systems. For example, the power flows on critical transmission lines can be displayed and monitored in control centers other than those in which each line is located.

NEPEX, NYPP, OH, and PJM are participating in a test procedure for Shared Activation of Reserves (SAR), in which operating reserve requirements are shared among the participating systems. During a recent one-year period, there were over 50 successful implementations of the SAR program by these systems.

NEPEX, NYPP, OH, and PJM also maintain an Interpool Computer Network, and discussions are underway with Hydro-Quebec regarding participation. A working group is charged with developing and maintaining procedures for processing data, collection and analysis of data, addition of new nodes to the network and coordination of troubleshooting and general maintenance matters.

The Task Force on Coordination of Operation sponsors a dispatcher training program for system operators from NPCC and neighboring systems. Two training seminars are held each year, with attendance averaging about 35 people per session.

The various NPCC Areas and the PJM pool share information on and coordinate generator and transmission maintenance schedules. The same systems also provide weekly updates on capacity margins, and participate in weekly conference calls to discuss anticipated conditions during the summer and winter peak demand periods.

The Northeast Power Coordinating Council (NPCC) represents 22 investor and publicly-owned utility systems serving about 44 million people in a one million square mile area encompassing the Northeastern United States and Eastern Canada. In the United States, NPCC members participate in either the New England Power Pool (NEPOOL) or the New York Power Pool (NYPP). In Canada, the 4 members — Ontario Hydro, Hydro-Quebec, and New Brunswick Power and Nova Scotia Power — are province-wide systems and make up 3 of NPCC's 5 Areas. Together, the NPCC members supply about 98% of all the electricity in the NPCC Region.

SERC

Southeastern Electric Reliability Council

Projected generating capacity margins in SERC are judged to be adequate during the review period based on current generating capacity expansion schedules and peak demand and energy projections. The SERC transmission systems are capable of supplying firm capacity requirements and additional emergency and economy energy transfers among the SERC Subregions, and between SERC and other regions.

Actual		Forecast		
Summer / Winter	1986 / 1986/87	1987 / 1987/88	1996 / 1996/97	Growth Rate (%/year)
Summer Peak—MW	105,570	105,770	129,054	2.2
Winter Peak—MW	101,849	104,299	127,054	2.2
Annual Energy—GWh	545,409	551,263	681,115	2.4
Installed Capability (summer)—MW	132,168	136,998	155,836	1.4

Peak Demand and Energy

The SERC Region covers a diverse geographic and socioeconomic area of 345,650 square miles and approximately 16 million customers in the Southeastern United States. The VACAR and Southern Subregions have historically been summer peaking, and the TVA and Florida Subregions have been winter peaking. Overall, SERC is a summer peaking Region and is forecast to remain so over the 1987-1996 period.

The SERC regional forecast has changed very little from that of last year, even though significant energy growth (about 5%) has occurred over the past year. The SERC 1987-1996 forecast of average annual growth rate of summer peak demand is down from last year's 2.4% to 2.2%. However, the peak demand projected for the end of the assessment period is about the same as projected last year. Similarly, the winter peak demand and annual energy growth rates have been reduced from 2.3% to 2.2% and from 2.5% to 2.4%, respectively. The four Subregions of SERC also project somewhat reduced average annual growth rates for peak demand and annual energy over the 1987-1996 forecast period.

A relatively large penetration of load management (LM) is expected by the end of the assessment period which contributes to the lower growth rate projections. This LM includes interruptible loads and directly controlled programs for cycling air conditioners, water heaters, and other devices. By 1996, directly controlled load management programs in SERC will approach 500 MW in Southern, over 1,000 MW in TVA, over 1,900 MW in VACAR, and about 1,000 MW in Florida.

Generating Capacity and Fuel

Capacity additions within the SERC Region for the 1987-1996 period include 4,863 MW in coal-fired units, 7,806

MW in 7 nuclear units, 1,300 MW in 8 pumped storage units, 5,788 MW in combustion turbine/combined cycle units, and 200 MW of conventional hydro capacity. This results in total capacity additions of 19,957 MW. Additional capacity of 3,711 MW is projected based on unit upratings and units returned to service from extended shutdown. Approximately 2,500 MW of new non-utility generation (NUG) penetration is also projected. Most of the large baseload units projected to come on line during this assessment period are well under construction with near-term operating dates. During the later years of the forecast period, most systems are planning for peaking or intermediate type capacity such as combustion turbines and combined cycle units because of system characteristics and regulatory and financial concerns.

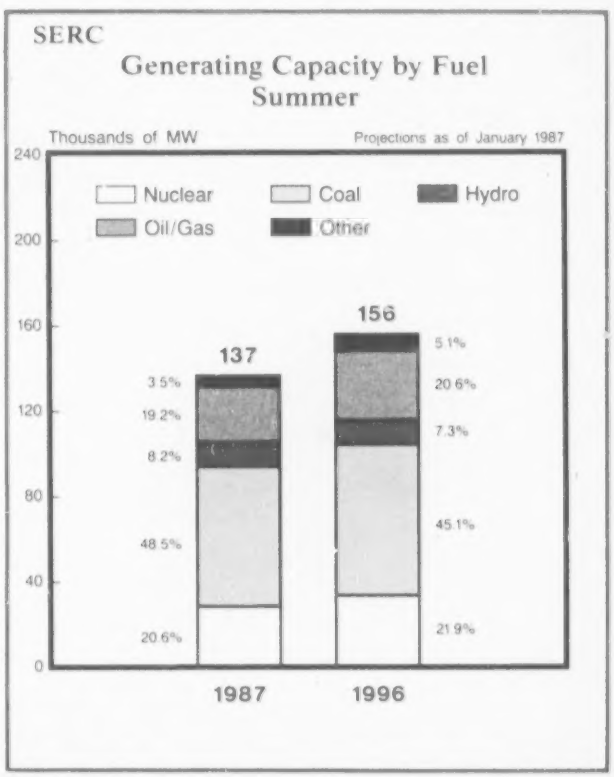
Projected generating capacity margins in SERC are judged to be adequate during the review period, based on current generating capacity expansion schedules and peak demand and energy projections. In addition to the installation of new capacity, modifications to existing units are underway and include unit upgrades, life extension programs, availability improvement programs, and reactivation of mothballed units. Power supply adequacy would be adversely impacted by regulatory decisions or other factors that would restrict the availability of existing or planned nuclear and coal-fired capacity.

By 1996, Florida plans to have about 5,300 MW of additional generating capacity. This increase is composed of units currently under construction, units being returned to service from cold standby, and new uncommitted capacity for the mid-1990's. By 1989, Florida will have installed 1,515 MW of new coal capacity and 140 MW of new gas turbine capacity. The uncommitted capacity planned for the end of the assessment period is primarily oil- or gas-fired combustion turbines and combined cycle units which total approximately 2,300 MW.

The Southern Subregion projects 5,087 MW of additional capacity during 1987-91, and an additional 233 MW by the end of the assessment period. Scherer 3 (833 MW—low-sulfur coal unit) was declared commercial on January 1, 1987. Major capacity additions include the two Vogtle nuclear units totaling 2,142 MW, the Miller 3 and 4 low-sulfur coal units totaling 1,332 MW, and the Scherer 4 low-sulfur coal unit at 808 MW. Coal will continue to be the predominant fuel throughout the assessment period.

No major changes were made in TVA expansion plans this year. By 1996, TVA plans to install 4,764 MW of additional capacity (four nuclear units). The Watts Bar units 1 and 2 are currently awaiting licensing and the Bellefonte units 1 and 2 are over 80% complete but are not scheduled for operation until the mid to late 1990's. A significant penetration of NUG capacity is not anticipated during this assessment period because of relatively low projected fuel costs.

Within the VACAR Subregion, approximately 5,200 MW of new capacity is projected by 1996. However, the only committed and identified additions include Duke Power Company's Bad Creek 1,000 MW pumped storage facility planned for the 1991-92 period, Southeastern Power Administration's two 75 MW Russell pumped storage units, and South Carolina Electric and Gas Company's 160 MW of combustion turbine/combined cycle units at Hagood. Carolina Power & Light Company's Mayo unit 2, a 690 MW coal unit, previously scheduled for 1992 was canceled during 1987 because of environmental rulings and associated economic reasons. The remaining capacity projections represent uncommitted and unlocated oil- and gas-fired unit additions during the 1990's. There is evidence that NUG capacity will contribute significantly to the VACAR capacity needs during this assessment period. For example, Virginia Power has received offers from prospective cogeneration developers totaling over 4,000 MW of NUG capacity and is currently negotiating for commitment of 1,000 MW by 1990. Other options such as outside capacity purchases or joint ownership are being actively pursued. The VACAR systems have committed for firm imports of over 900 MW throughout this assessment period.

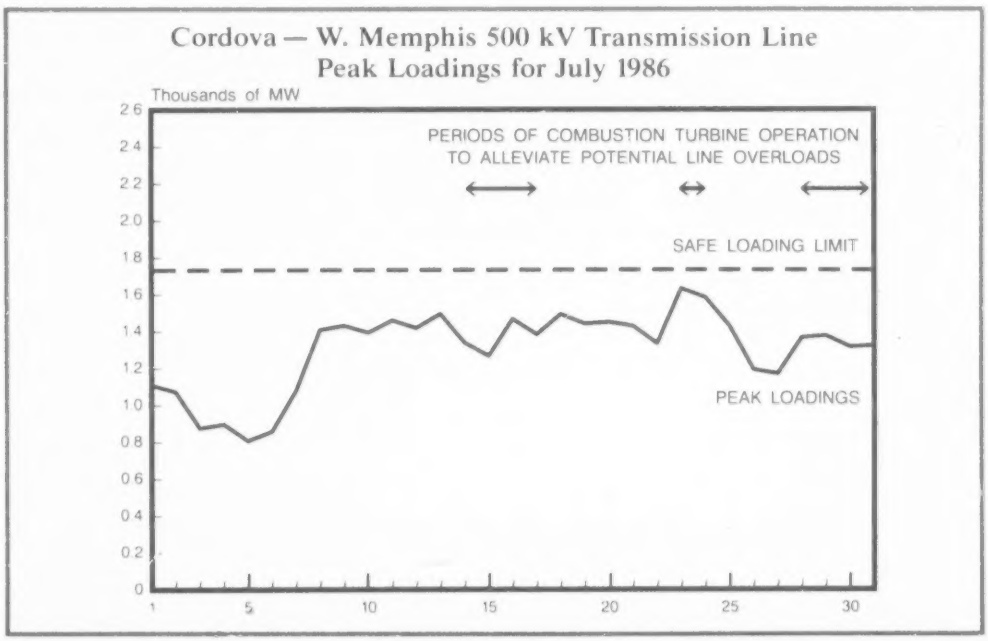


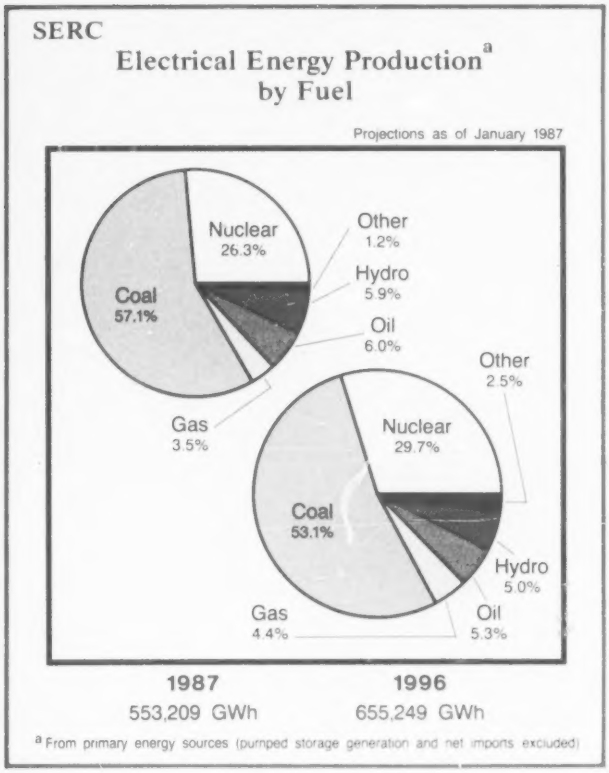
Transmission

SERC systems have coordinated transmission planning and operations to assure the continued use and expansion of a reliable transmission network. Analysis of coordinated intraregional and interregional studies indicates that existing facilities, along with those planned to meet the future reliability needs of the SERC Subregions, will also provide adequate energy transfer capability between SERC and other regions and among the SERC Subregions. All systems expect to meet SERC reliability criteria during the review period.

Heavy utilization of the SERC transmission systems is projected to continue in certain portions of the network through this assessment period as systems strive for optimum economic operation. Even though major reliability concerns are not anticipated, several key transmission interfaces or tie lines between utilities, subregions and regions will be monitored because of their high loadings during certain interregional and intraregional energy transfers. Included in this list are:

- **The TVA-MAIN Interface near Paducah, Kentucky**—This Interface appears to be the primary SERC transmission sensitive area throughout this assessment period due to the amount of load at a large DOE uranium enrichment plant at Paducah, Kentucky, generation levels at nearby plants, and various interregional and intraregional energy transfers. To mitigate heavy loading problems, a special protective scheme has been installed to trip multiple generating units during certain contingency conditions. There are no additional transmission facilities planned to permanently alleviate these problems because of the uncertainty of the DOE plant load.
- **The Southern-VACAR Interface near the Savannah River**—As discussed in the Transmission Assessment chapter, this Interface can become heavily loaded by a combination of events. Intraregional and interregional energy transactions can impact loadings on this Interface even when the transactions are not between the two directly interconnected parties. Even though additional transmission enhancements were added during 1986 which mitigated some of the heavy loading problems on the Savannah River Interface, it is expected that operating procedures established to reduce these loadings will remain in effect for the foreseeable future.
- **The TVA-SPP Interface near Memphis, Tennessee**—Sensitive to both west-east and north-south energy transfers, operating procedures have been implemented when necessary to alleviate heavy loadings on the Cordova-West Memphis 500 kV transmission line. These procedures include (a) opening certain underlying 161 kV transmission lines to reduce the possibility of potential overloads, (b) curtailing energy transactions, and (c) running local generation (combustion turbines) off economic dispatch. The adjacent figure illustrates the daily peak loadings on this 500 kV line during July 1986 when operating procedures were implemented on several occasions to mitigate heavy loading conditions. Major EHV reinforcements are planned during this assessment period that will significantly reduce (but not entirely eliminate) these heavy loading concerns.





- **Southern-Florida Interface**—Even though power transactions between the Southern electric system and peninsular Florida have reduced significantly since 1985, firm Florida imports of 2,400 MW are scheduled through most of this assessment period. If oil prices increase significantly, this Interface will again approach maximum allowable loadings for most of the hours during the year.

The existing SERC transmission systems include over 19,600 miles of 230 kV and almost 7,000 miles of 500 kV transmission lines. During the review period, 1,525 miles of 230 kV and 764 miles of 500 kV lines are expected to be added in the Region, including two major 500 kV transmission interconnections between SERC and SPP and one major 500 kV transmission interconnection between SERC and ECAR. These projections represent no major change from projections made in 1986.

Permitting of a key 500 kV line in Florida awaits the development of State standards on electric and electromagnetic field strength. No major transmission delays have occurred in the other Subregions.

Intraregional and Interregional Coordination

SERC transmission systems are directly interconnected with the transmission systems in four other Regional Councils (SPP, MAIN, ECAR, MAAC), and SERC members actively participate in intraregional and interregional studies. These include reliability appraisals of the bulk electric transmission systems before each summer and winter peak period and longer range studies on a periodic basis. Many special reliability studies are also conducted in anticipation of future operating concerns.

Interregional coordination is achieved under specific reliability coordination agreements between various SERC systems and systems in adjacent Regional Councils. Interregional working groups study, review, and appraise short-term system performance and provide for long-range coordination of future plans. The annual report of the SERC Reliability Review Subcommittee demonstrates that the SERC systems are being planned in accordance with regional reliability criteria and that the systems are fulfilling their obligations to keep other systems informed on matters relating to system reliability. It also attests to the fact that expansion plans in the Region have been adequately coordinated within SERC and that the necessary studies have been made to determine the adequacy of interconnections between SERC systems and contiguous regional systems. This report also furnishes an opportunity for subregional systems in SERC to express to SERC their concerns on current and future matters which may adversely affect the reliability of bulk electric systems.

The following is a list of transmission systems studies in which SERC systems have participated during 1986. They include reliability assessments, planning studies, operating studies, and special engineering analyses of particular potential problem situations. They generally include transmission line loading analyses and system stability evaluations.

- VACAR-Southern-TVA (VST)
- VACAR-ECAR-MAAC (VEM)
- MAIN-ECAR-TVA (MET)
- Florida Coordinating Group (FCG) Coordinated Studies
- VACAR Coordinated Studies

In order to maintain up-to-date and meaningful information for system operators, periodic updates of the initial studies, reflecting the most recent system changes, are made in addition to the traditional "pre-season report," which projects seasonal operating incremental transfer capabilities.

Regional and interregional coordination is continually exhibited by the heavy utilization of various transmission interconnections for the purpose of optimum economic operation and emergency assistance.

Operations

The SERC bulk electric transmission systems configuration ten years from now will not be significantly different from the present day system. The transmission systems are basically in place for most of the new capacity that is planned. Greater dependence on load management, an expectation of moderate load growth, and the sharing of generation capacity will likely reduce operating margins throughout this period. This will place an even greater burden on the bulk transmission systems and will require continued coordination and communication among SERC systems and adjacent regional systems. Operators may be forced to take intervening actions on a more frequent basis to ensure that system security is maintained.

The SERC systems are responding to this operations challenge with a multi-phased approach. Several systems are upgrading their control centers with new Energy Management Systems (Southern in 1986, Duke in 1989, and TVA in 1988) and enhancing their associated communication channels. Many systems within SERC are also developing with other regional systems in ECAR, MAAC, and NPCC a new communication network for the exchange of real-time data for system security purposes. System operator training programs also continue to be upgraded using the latest tools available in the industry.

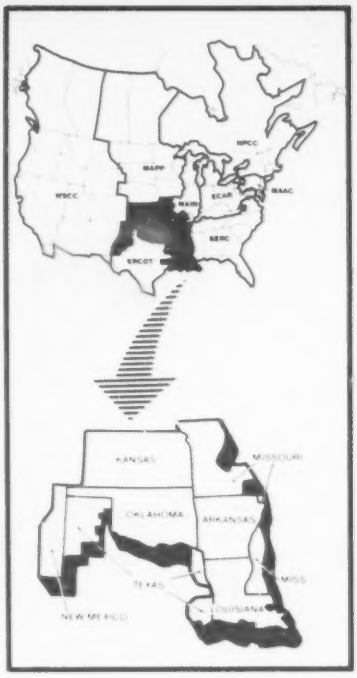
Specific examples of actions taken in 1986 to improve operating practices were:

- Florida utilities established a statewide Mutual Aid Agreement. This provides a method for electric utilities which sustain damage from natural disasters to obtain emergency assistance from other utilities.
- Florida utilities also established a Procedure for Reporting and Resolving Potential Transmission (Loading) Problems. This procedure not only reduces heavy line loadings but does it economically.
- The Southern electric system Power Coordination Center revised its short-range preparedness plans following a fire in the building where the Center is located. Under development is a long-range disaster prevention plan.
- TVA has established an alternate control center and has trained personnel in its use.
- Working together, VACAR members have established an operating arrangement called VACAR NET. This "real-time" computer-based system will constantly display on control room monitors the economy energy cost data and other operating information relating to the VACAR systems. This provides additional assistance to system operators in conducting economic energy transactions and assuring continued reliable operation of the bulk electric system within VACAR. This network replaced the existing teletype network previously in use among the members.

SERC membership includes 28 systems located in 9 states in the southeastern United States. SERC is divided into 4 diverse subregions which are identified by Florida (the Florida peninsula), Southern (the geographical area of the Southern electric system), TVA (the Tennessee Valley Authority area) and VACAR (the Virginia-Carolinas area). Total population in the Region is about 25 million.

SPP

Southwest Power Pool



Peak demand and energy forecasts have been reduced from last year's projections. Much of the Southwest Power Pool has been experiencing an economic recession. Areas dependent on petroleum and agriculture have fared worst. The positive effect is that with lower demand growth the need for additional generating capacity is also reduced. During the next ten years, generating capacity and transmission will approach minimum desirable levels but are expected to be adequate.

Actual		Forecast		
Summer Winter	1986 1986/87	1987 1987/88	1996 1996/97	Growth Rate (%/year)
Summer Peak—MW	47,123	46,246	55,442	2.0
Winter Peak—MW	33,877	34,433	41,515	2.1
Annual Energy—GWh	216,501	220,532	266,172	2.1
Installed Capability (summer)—MW	65,102	64,643	66,777	0.4

Peak Demand and Energy

Forecasts of peak demand and annual energy are lower than last year's projections as a result of economic conditions. Louisiana and Oklahoma are dependent on agriculture and petroleum, both of which have been hard hit by the local economic recession. Numerous bank closings bear testimony to the impact.

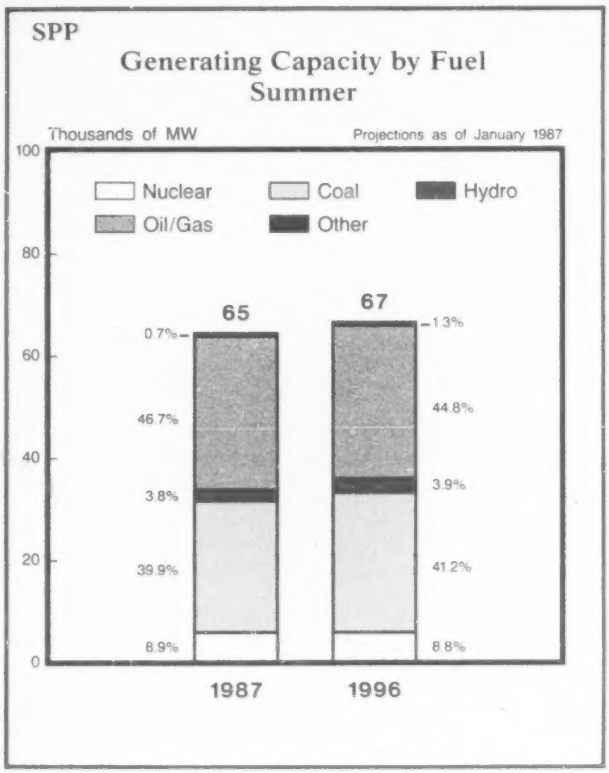
From 1987 to 1996, peak demand is expected to grow at 2.0% annually, down from last year's forecast of 2.3%. Peak demand growth has declined steadily since 1978 when a 10-year rate of 6.2% was forecast. There are indications that the bottom has been reached. For example, the price of oil soared to over $30 per barrel in the early 80's, then down to $10 and presently is trying to stabilize at about $20. Annual energy growth has been reduced from a 2.2% annual rate to the current forecast of 2.1% for the next decade.

Load management accounts for some of the decrease in demand and energy growth. Active load management, under control of the system operator, was 1,087 MW in 1986, increasing to 1,766 MW by 1996 or 3.2% of the 1996 peak demand. Since these numbers are relatively small, they do not represent a major factor in evaluating reliability. However, they are significant when coupled with other forms of load management, such as passive and customer controlled load management. Those systems which depend on load management to keep demand within their capacity limits will need to closely monitor the effectiveness of their load management programs.

Generating Capacity and Fuel

There were 64,812 MW of existing generating capacity as of December 31, 1986. Natural gas and oil fuel 47.1% of the capacity. Gas accounts for 18.9%, oil 2.5%, while 25.7% can burn either. Coal is used by 39.9%, nuclear 8.9% and hydro and other 4.1%. Similar capacity data for 1987 and 1996 are shown on the accompanying illustrations.

Three generators were placed in service in 1986. Dolet Hills 1 is a 640 MW coal unit (577 MW is reported in SPP capacity); Oklaunion 1 is a 665 MW coal unit (104 MW is reported in SPP capacity); and Riverbend 1 is a 936 MW nuclear unit. Installed summer capacity increased 2,877 MW from 1985 to 1986.



The capacity projections made in 1985 for the years 1987 to 1995 increased capacity by 4,228 MW. Current plans are to increase capacity 1,931 MW by 1995 and 2,134 MW by 1996. Thus, in one year, capacity additions through 1995 have decreased 2,300 MW or 54%.

Only 4 generators 100 MW or larger are currently scheduled to be installed between 1987 and 1996. These are 2 coal units sized 540 MW and 630 MW and 2 cogenerators sized 100 MW and 300 MW. A degree of uncertainty is associated with all 4 generators. Four other large generators that were in last year's future plans have been deferred or canceled.

Non-utility generation is expected to be 228 MW in 1987 and 654 MW by 1996 which is 1.0% of the total capacity at the end of the 10-year review period.

Power supply will be adequate for the next 10 years. The SPP capacity margin will decrease from 29.3% in 1987 to 16.7% in 1996. The 1996 value represents the Southwest Power Pool minimum capacity margin requirement. As the minimum is approached, some systems may be at or below their minimum.

Transmission

Transmission placed in service in 1986 was virtually as planned. This included 172 miles of 230 kV and 79 miles of 345 kV transmission lines.

SPP now has 3,990 miles of 230 kV, 4,533 miles of 345 kV and 2,079 miles of 500 kV transmission lines in service. There are 3 direct current back-to-back converter interconnections from SPP to other regions: 1 to ERCOT and 2 to WSCC, with a total capability of 600 MW.

In the next decade, it is planned to install 984 miles of 230 kV, 570 miles of 345 kV and 309 miles of 500 kV transmission lines. Significant interregional circuits include a third 500 kV ac interconnection with SERC (TVA) and a second dc interconnection with ERCOT.

The bulk transmission system and the interconnections with other regions provide a high level of reliability for SPP, its members, and the other interconnected regions.

Various lines have been heavily loaded in past years by economy transfers. The 500 kV Sheridan-El Dorado line in Arkansas was heavily loaded in the past, but a parallel 500 kV line and additional generation in Louisiana have eliminated the problem. The West Memphis-Cordova 500 kV interconnection between SPP and SERC averaged over 73% of its normal rating during July 1986. There are no lines that represent significant bottlenecks to economy transfers at this time.

No transmission lines have been delayed to the extent that a severe reliability problem was caused. The 155-mile 400 kV direct current line from Walker County to the South Texas Project has encountered difficulty in obtaining Texas PUC certification. Therefore, approval is being sought for an alternative location in northeast Texas with back-to-back dc converters and a 345 kV ac line. The original project was planned for 1984; the current in-service date for the alternate plan is 1990.

Segments of the 120-mile 345 kV line from Flint Creek in Arkansas to Morgan in Missouri will have delays of 6 to 24 months because of delays in obtaining approval of environmental studies. Final completion is planned for December 1988.

Operations

There has been no appreciable reduction of operating margins. Capacity operating margins are maintained at the required 6% of annual peak load responsibility or higher. Problems due to operating near transmission line power transfer limits generally decreased in the last year or two. The year 1986 saw reversal of the normal SERC to SPP economy exchanges. At times, a phase shifting transformer, installed to control expected east-to-west power transfer, has forced west-to-east flows over other parallel paths. The utilities involved are discussing various solutions.

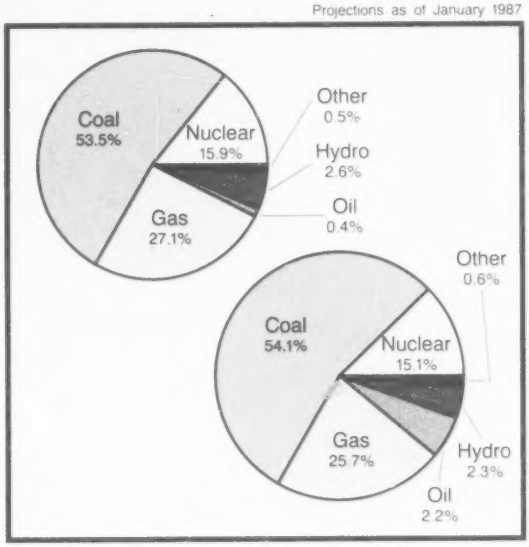
The Southwest Power Pool has no special conditions that require Special Protective Systems in order to achieve higher power transfers than would otherwise be

possible. The bulk transmission system is adequate throughout the forecast period. One generating station in Missouri has operating guidelines to reduce line loading during certain contingencies. Also, the 345 kV St. Joseph-Cooper interconnection to MAPP is closely monitored so its outage would not overload the underlying lower voltage transmission lines.

SPP

Electrical Energy Production[a] by Fuel

Projections as of January 1987



[a] From primary energy sources (pumped storage generation and net imports excluded)

Subregions

Northern—The Northern Subregion expects a 2.0% annual average growth rate in demand for 1987 to 1996. Except for the Hugoton gas field in Kansas, petroleum is a minor industry. Currently, the predominant generating capacity fuel is coal, at 69%, with gas and oil at 23% and nuclear at 7%. This mix has produced a stable, low cost fuel supply. By 1996, gas and oil will increase slightly to 25% of the total.

Southeastern—Peak demand growth rate for 1987 to 1996 is forecast to be 1.9% per year. The Southeastern Subregion primarily uses gas and oil for fuel with 61% of the 1986 capacity on these fuels. Coal is 22% and nuclear is 17%. Public attention has recently been focused on nuclear issues. In addition to the popular opposition to nuclear costs, there have been lengthy regulatory hearings to allocate costs of nuclear units among the various participants.

West Central—The West Central Subregion is forecasting a 2.2% annual average peak demand growth rate over the forecast period. This is in anticipation of improving economic conditions. The 1986 capacity mix is balanced with 47% gas and oil and 42% coal. There is 11% hydro because the Southwestern Power Administration reports in this Subregion. There is no existing nuclear generation and none planned for the next 10 years.

Regional and Interregional Coordination

SPP participated in the recent MAPP-MAIN-SPP (MMS) study. This study examined the potential for economy transfers among these three regions during the next ten years by determining incremental and decremental production costs by season and by region and subregion. These production costs were matched to develop the various potential combinations of transfers versus differential costs.

Northern Subregion utilities of SPP were observers for a series of load flow studies made by the Western Area Power Administration (WAPA) and Southwestern Power Administration (SWPA) engineers. These studies investigated the technical aspects of proposed energy transfers from WAPA in the WSCC Region to preference customers and SWPA in the SPP Region.

The planned Flint Creek to Morgan 345 kV and the completed Maid to Flint Creek 345 kV lines are examples of coordination among various types of utility systems. The five parties involved in this effort consisted of one municipal, one generation and transmission cooperative, one state power agency, and two investor-owned utilities.

An SPP transmission line outage data base is under development. This will improve the realistic assessment of transmission system reliability for both planning and operations.

Financial and Regulatory Issues

Acid rain legislation may have limited impact on SPP. Many of the coal-burning units use low sulfur Western coal or already have scrubbers so that sulfur removal is not a major problem. The impact will depend on the emission limits which are established for sulfur dioxide and the oxides of nitrogen.

The Southwest Power Pool (SPP) includes 38 power suppliers serving customers in the states of Kansas, Oklahoma, Missouri, Arkansas, Mississippi, Louisiana, Texas and New Mexico. The membership is composed of 11 municipals, 2 state agencies, 7 cooperatives, 17 investor-owned utilities and 1 Federal agency.

WSCC

Western Systems Coordinating Council

WSCC has made major progress in a comprehensive review of its bulk electric system reliability criteria, in developing project review procedures to deal with problems related to heavy transmission system utilization, and in the use of remedial action schemes as a substitute for additional transmission facility investment. Projected WSCC capacity margins for the 1987-1996 period will meet present reliability criteria. In addition, the transmission systems as planned will be adequate to serve projected loads.

Actual		Forecast		
Summer	1986	1987	1996	Growth Rate
Winter	1986/87	1987/88	1996/97	(%/year)
WSCC — U.S.				
Summer Peak—MW	81,787	85,932	103,604	2.1
Winter Peak—MW	76,171	82,040	97,978	2.0
Annual Energy—GWh	480,218	500,574	598,002	2.0
Installed Capability (summer)—MW	124,140	123,087	134,372	1.0
WSCC — Canada				
Summer Peak—MW	9,496	10,214	13,361	3.0
Winter Peak—MW	11,751	12,939	16,882	3.0
Annual Energy—GWh	72,922	76,474	101,905	3.2
Installed Capability (winter)—MW	17,686	17,686	19,574	1.1
WSCC — Mexico				
Summer Peak—MW	619	682	1,215	6.6
Winter Peak—MW	393	441	785	6.6
Annual Energy—GWh	2,834	3,231	5,865	6.8
Installed Capability (summer)—MW	828	1,028	1,418	3.6
WSCC — Total				
Summer Peak—MW	91,768	96,769	118,103	2.2
Winter Peak—MW	88,315	95,243	115,645	2.2
Annual Energy—GWh	555,974	580,279	705,772	2.2
Installed Capability (summer)—MW	142,885	142,032	155,412	1.0

Peak Demand and Energy

The accompanying tables provide a comparison of this year's forecast of peak demand and energy with last year's forecast and summarize the 1986 peak demand and energy experience.

WSCC (U.S., Canada and Mexico)
Comparison of Forecasts

	This Year's Forecast (1987-1996)	Last Year's Forecast (1986-1995)
10-Year Forecasts:		
Summer Peak Demand Growth Rate (%/yr)	2.2%	2.4%
Annual Energy Growth Rate (%/yr)	2.2%	2.4%
Forecasts for Year 1995:		
Summer Peak Demand—MW	115,715	118,101
% Change	-2.0%	
Annual Energy—GWh (Median Hydro)	689,968	698,709
% Change	-1.3%	

WSCC (U.S., Canada and Mexico)
1986 Peak Demand and Energy Experience

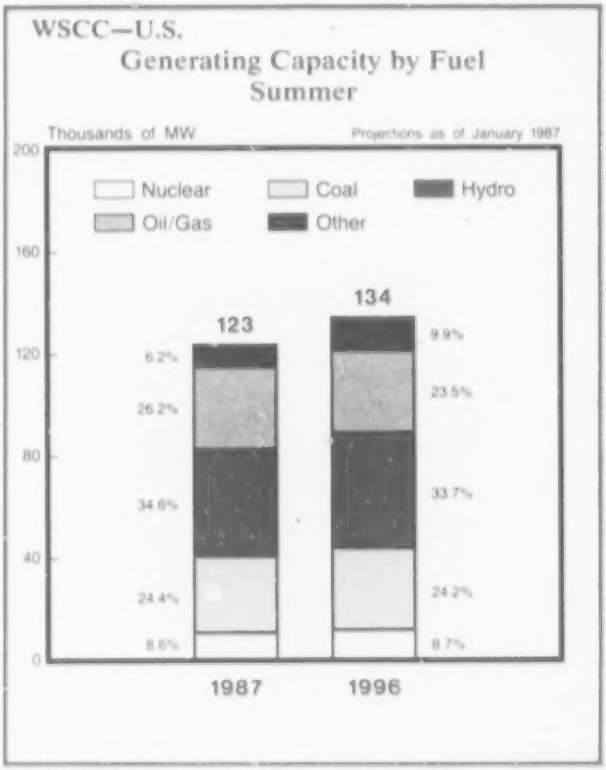
	1986 Actual vs 1985 Actual	1986 Actual vs 1986 Forecast
Summer Peak Demand	-1.6%	-3.8%
December Peak Demand	-2.6%	-5.8%
Annual Energy	0.5%	-1.2%

Generating Capacity

Net hydroelectric generating capacity additions (3,357 MW) planned through the 1987-1996 period represent 21% of the total planned generating capacity additions within the Region. Net coal-fired generating capacity additions (6,383 MW) represent 40% and non-utility generation (NUG) additions (4,890 MW) represent 31% of WSCC's planned generating capacity additions.

Generation capacity margins projected for the summer peak decrease from 30% to 22% over the next 10 years. These capacity margins are adequate and will enable WSCC to respond to additional load growth above that forecasted in the event of an accelerated economic recovery.

Currently, 12,272 MW of the total 15,803 MW net capacity additions planned to be operational in 1996 are not yet



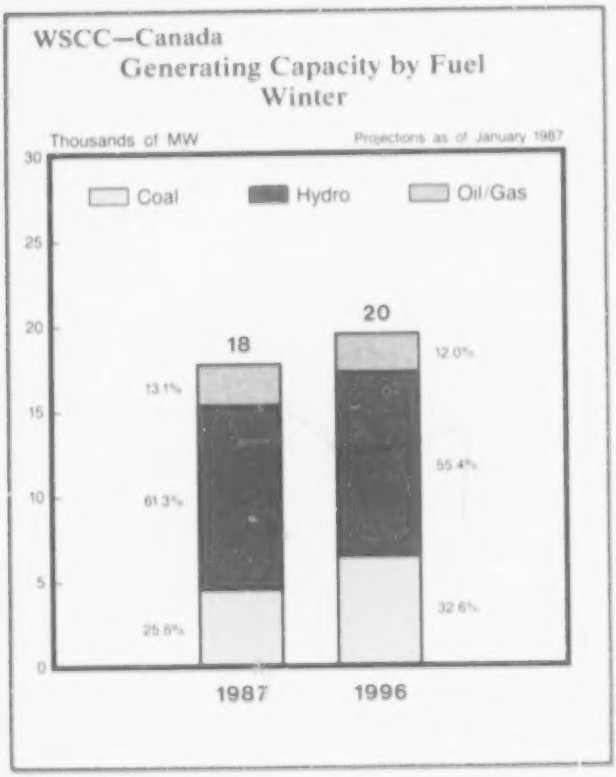
under construction. With the exception of NUG additions, which typically have a one- to two-year construction period, the Region will have reduced ability to respond to increases in demand in the 1990's if construction of this capacity does not proceed on schedule.

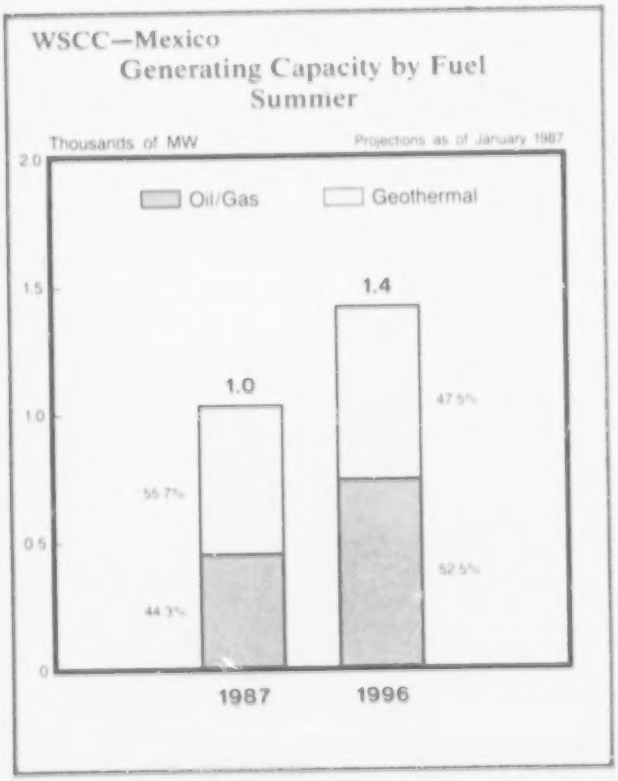
Transmission Adequacy and Operations

The WSCC transmission systems are adequate to accommodate anticipated firm and most economy energy transfer schedules during the 10-year period (1987-1996).

An issue which is expected to be of continuing concern during the next 10 years is the effect of heavy economy transfers on bulk electric power system reliability. The Region's diverse load and capacity resource mix, combined with localized surpluses of baseload capacity, large fuel price differentials, and efforts to increase regional operating efficiency will continue to make economy energy transfers between areas economically beneficial for buyers and sellers alike.

Over the last two years, reduced gas and oil prices have allowed utilities to generate energy more economically with local gas- and oil-fired units. In addition, new baseload generating units have recently been placed in service within areas that have historically imported relatively large amounts of energy. These conditions have re-





sulted in reduced economy energy transfers within the Region. It is expected that over the long-term, the cost differential between gas/oil-fired generating units and other generating resources will increase, resulting in a return to more economy energy transfers.

Because of the expected increases in economy energy transfers, portions of the regional transmission systems will be loaded to higher levels for sustained periods of time. Thus, the bulk transmission systems will be operated to provide greater economic advantages even though this mode of operation will pose greater risks to system reliability due to reduced operating margin.

WSCC member systems are making a concerted effort to maintain an acceptable level of existing and future system reliability while accommodating higher transfer levels. Major work has been completed and additional work is underway to improve the reliability of the Pacific Intertie and associated remedial action schemes. Relays and associated equipment are being replaced and additional circuit breakers and redundant communication systems are being added where appropriate. An independent detection scheme to initiate controlled islanding for loss of the two 500 kV ac lines of the Pacific Intertie, should the primary transfer trip scheme fail, has been placed in service in a monitor mode to evaluate its feasibility.

Operating restrictions (defined by nomograms) have been imposed to limit simultaneous imports to California. These operating restrictions are required to assure that acceptable system performance can be maintained in the event of a disturbance.

The Council has supported a number of other activities in an effort to promote an acceptable level of future system reliability. Some of the more noteworthy activities include the following:

- During 1986, the Council initiated a comprehensive review of its planning and operating reliability criteria. The review is scheduled to be completed during 1987.
- Special study groups have been formed to evaluate major projects planned during the next ten years to ensure that performance of each project is in compliance with WSCC criteria.
- WSCC System Disturbance Reports are routinely analyzed to identify the factors which contributed to the disturbance and improvements which should be made. The status of implementing disturbance report recommendations is updated three times per year. Since 1979, over 250 disturbance report recommendations have been implemented to enhance the reliability of the WSCC interconnected systems.
- Through WSCC's Dispatcher Training Program, operating personnel are schooled in interconnected sys-

tems operation to promote overall system reliability. During 1986, 246 participants attended the 12 training sessions which were held at various locations throughout the WSCC Region and received more than 6,000 man-hours of training.

During the 1987-1996 time frame, several key planned transmission projects and transfer path uprates are likely to have a significant effect on the operation of the WSCC interconnected systems and their energy transfer capability. These projects and uprates include:

- Upgrading the transfer capability of the Northwest to California 500 kV ac Pacific Intertie from 2,800 MW to 3,200 MW—1987.
- Completion of the 1,600 MW Intermountain Power Project Generating Plant in Utah and the associated ± 500 kV dc line to California — 1986-87.
- DC Terminal Expansion Project, upgrading the Celilo-Sylmar ± 500 kV dc line from 2,000 MW to 3,100 MW—1989.
- Completion of the third Northwest to California 500 kV ac Pacific Intertie — 1991.
- Increasing the Arizona-California transfer capability from 4,700 MW to 5,200-5,500 MW — 1987.
- The addition of phase shifting transformers in southwestern Colorado to partially control loop (parallel) flow — 1988.

The Council has placed a high priority on studying the effects of these projects on the reliability of the WSCC interconnected systems and evaluating alternative remedial action schemes which will confine the effects of disturbances involving these projects to the project participants, consequently minimizing the effects on neighboring systems.

One issue that the Council and its members continue to study is development of an equitable solution to major and minor loop (parallel) flows. Loop flow requires some utilities to provide uncompensated transmission service to others.

Non-Utility Generation

Of the four WSCC areas, the California-Southern Nevada Power Area is projecting the highest growth in non-utility generation. Increased NUG facilities have been stimulated by the California Regulatory Commissions' interpretations of the Federal government's Public Utility Regulatory Policies Act (PURPA) of 1978. Because of the oversupply of NUGs, the California Public Utilities Commission has suspended most of the standard offers which the California investor-owned utilities were required to sign to buy electric power from developers.

In most cases, the utilities have little or no control over non-utility generation operation, and must accept the energy when delivered. Since most of these NUGs are baseload in nature, the host utility's load-following generating capacity must work harder, which increases wear and tear, maintenance, and perhaps outage rates on thermal equipment. In addition, many NUGs are small, low-voltage units and are likely to separate from the system during distribution system disturbances. These factors, plus uncertainty about the long-term economic viability of non-utility generation, raise significant concerns about reliability issues in those areas expecting major NUG development.

Northwest Power Pool Area

The Northwest Power Pool (NWPP) Area is comprised of the states of Washington, Oregon, Idaho, Utah, portions of Montana, Wyoming, Nevada and California, and the Canadian provinces of British Columbia and Alberta.,

Projections of peak demand and energy requirements for the 1987-1996 period are presented in the accompanying tables. Winter generating capacity margins for this winter peaking area decrease from 24 to 14% over the next 10 years but will be adequate to maintain area reliability.

Northwest Power Pool (U.S.)
Comparison of Forecasts

	This Year's Forecast (1987-1996)	Last Year's Forecast (1986-1995)
10-Year Forecasts:		
Summer Peak Demand Growth Rate (%/yr)	1.5%	1.8%
Annual Energy Growth Rate (%/yr)	1.6%	2.0%
Forecasts for Year 1995:		
Summer Peak Demand—MW	30,242	30,530
% Change	-0.9%	
Annual Energy—GWh	215,929	219,006
% Change	-1.4%	

Northwest Power Pool (Canada) Comparison of Forecasts		
	This Year's Forecast (1987-1996)	Last Year's Forecast (1986-1995)
10-Year Forecasts:		
Summer Peak Demand Growth Rate (%/yr)	3.0%	2.8%
Annual Energy Growth Rate (%/yr)	3.2%	2.9%
Forecasts for Year 1995:		
Summer Peak Demand—MW	12,900	13,174
% Change	-2.1%	
Annual Energy—GWh	98,724	95,559
%Change	3.3%	

Progress continues in completing the Colstrip 500 kV transmission system. A temporary Colstrip generator tripping scheme for loss of either section of the Taft-Dworshak-Hatwai 500 kV line will remain in service until the Taft-Bell 500 kV line is energized in the fall of 1987.

The Cranbrook-Langdon 500 kV interconnection between British Columbia and Alberta has been in service since January 1986, strengthening the interconnection between Alberta and British Columbia.

Upon completion of tests associated with new series capacitors between Table Mountain and Tesla Substations in California early in 1987, the transfer capability of the ac Pacific Intertie will be upgraded from 2,800 MW to 3,200 MW. This uprate has been considered in the seasonal nomograms prepared by WSCC. The amount of Northwest generator tripping will be increased for single and double line outages at the new transfer capability level.

The Celilo-Sylmar dc expansion project to increase the capacity of the line from 2,000 MW to 3,100 MW by 1989 has entered the construction phase. Specifications are being prepared for related dynamic voltage support facilities to be installed at Malin and Table Mountain Substations as part of the project.

Planning is in progress regarding the upgrade of the ac Pacific Intertie to 4,800 MW through construction of a third 500 kV line in northern California. The new 500 kV line, scheduled for completion by 1991, will extend from Tesla Substation in California, north to the Malin-Meridian 500 kV line in Oregon. Addition of the third ac Pacific Intertie line should eliminate the need for the NE/SE Islanding Scheme as remedial action for loss of the two existing ac Pacific Intertie lines. A decision regarding the actual routing of the line is expected in 1987. All routes under consideration provide some separation from the existing Malin-Round Mountain lines to minimize the likelihood of a three-line outage.

An aggressive program is in progress to improve the reliability of the Pacific Intertie by taking measures to reduce the likelihood of outages, and by upgrading and/or replacing remedial action schemes to insure proper remedial action for Pacific Intertie outages. The program is scheduled to be completed in three phases by 1990. Measures being taken to improve remedial action schemes involve the use of redundancy, monitoring, and separation of schemes to reduce the likelihood of a major remedial action scheme failure.

Rocky Mountain Power Area

The Rocky Mountain Power Area (RMPA) consists of Colorado, eastern Wyoming and a small portion of South Dakota. The accompanying table presents this year's forecast of peak demand and energy as compared to last year's forecast. Summer generation capacity margins will decrease from 35% to 27% over the next 10 years but will be adequate to maintain area reliability.

Rocky Mountain Power Area Comparison of Forecasts		
	This Year's Forecast (1987-1996)	Last Year's Forecast (1986-1995)
10-Year Forecasts:		
Summer Peak Demand Growth Rate (%/yr)	2.6%	3.3%
Annual Energy Growth Rate (%/yr)	2.8%	2.9%
Forecasts for Year 1995:		
Summer Peak Demand—MW	7,493	8,213
% Change	-8.8%	
Annual Energy—GWh	47,315	47,886
% Change	-1.2%	

The 100 MW Nucla Fluidized Bed Combustion Demonstration Project, located in western Colorado, is scheduled to begin operation in the third quarter of 1987. This two-year testing program should demonstrate the ability of this technology to burn a wide range of fuels with improved boiler efficiency and with no scrubbers required to maintain air quality.

The Rifle-San Juan 345 kV transmission line, 265 miles in length, is nearing completion. The Rifle to Montrose

section of this line is now in service. The Rifle-San Juan line will serve loads in western Colorado as well as strengthen the interconnected transmission system between Colorado and the Arizona/New Mexico area.

The transmission system northeast of Denver continues to be heavily loaded. To relieve the heavy loading, plans are underway to uprate certain existing line sections and to construct a new 230 kV line between the Ault Substation and Ft. St. Vrain Switchyard, both in Colorado. Much of this work is scheduled during the next 3 to 5 years.

The Hayden-Blue River 230 kV transmission line, 90 miles in length, is scheduled for completion during the fourth quarter of 1987. This line will substantially increase transmission capacity between western and eastern Colorado.

Construction of a third ac-dc-ac tie between WSCC and MAPP in southwestern Nebraska, near Sidney, is scheduled for completion in 1987. The transfer capability of this dc tie is 200 MW in either direction.

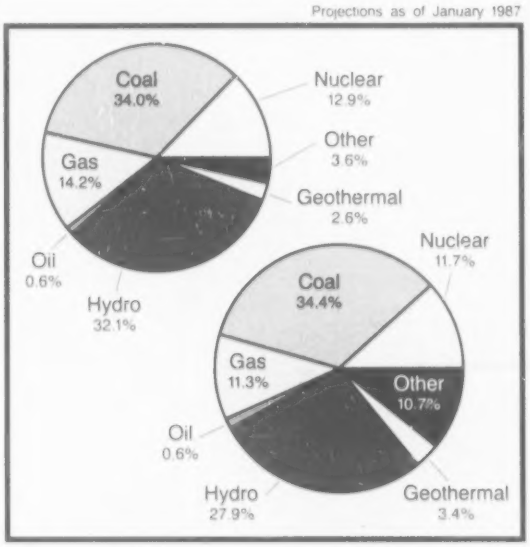
The existing 138 kV transmission system connecting northern Colorado and Utah is very heavily loaded at times. These heavy loading conditions are due to a combination of firm schedules, economy schedules, and loop flow. To provide relief, plans are underway to construct, by the early 1990's, a new 345 kV line between Colorado and Utah.

During 1986, loop flow continued to adversely impact the transmission system between the Arizona/New Mexico and Colorado/Utah areas. In an effort to mitigate this problem, the Western Area Power Administration is proceeding with plans to install phase-shifting transformers to control loop flow in the western Colorado portion of the interconnected system.

Generating capacity has been installed in RMPA which is surplus to the near-term load requirements within the area. A significant amount of coal-fired generating capacity is available for area load growth and export to other areas. Surplus capacity (approximately 1,000 MW) was available in the 1986 summer and 1986/87 winter operating seasons. The export of surplus generation is limited by the transmission capacity to outside areas and the marketability of surplus energy which has been affected by lower gas and oil prices and new baseload nuclear units recently placed in operation in Arizona and California. The surplus baseload capacity will be available for 5 to 10 years before being absorbed by area growth.

Growth in NUG facilities has been relatively slow in RMPA. This can be attributed to the substantial amount of surplus coal-fired generating capacity available within the area which results in low avoided costs.

WSCC—U.S.
Electrical Energy Production[a]
by Fuel



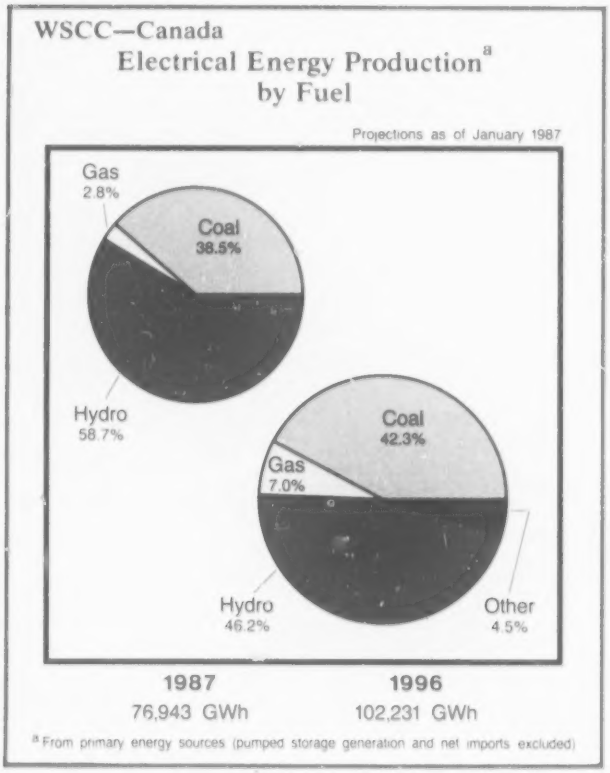
[a] From primary energy sources (pumped storage generation and net imports excluded)

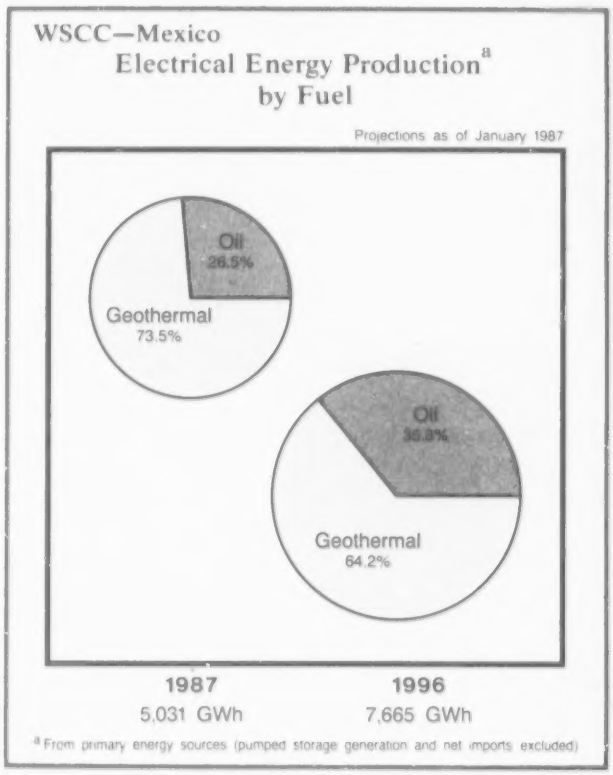
Arizona-New Mexico Power Area

The Arizona-New Mexico Power Area (AZ-NM) consists of Arizona, most of New Mexico and the western-most part of Texas. The accompanying table depicts this year's forecast of peak demand and energy as compared to last year's forecast. Generating capacity margins during summer peak will decrease from 37% to 28% over the next 10 years but will be adequate to supply projected loads.

Arizona-New Mexico Power Area
Comparison of Forecasts

	This Year's Forecast (1987-1996)	Last Year's Forecast (1986-1995)
10-Year Forecasts:		
Summer Peak Demand Growth Rate (%/yr)	3.1%	3.6%
Annual Energy Growth Rate (%/yr)	3.2%	3.3%
Forecasts for Year 1995:		
Summer Peak Demand—MW	14,130	14,464
% Change	-1.9%	
Annual Energy—GWh	69,861	70,452
% Change	-0.8%	





Projected net generating capacity additions for the 1987-1996 period total approximately 2,940 MW and are predominately coal-fired and nuclear units.

During 1986, two Palo Verde nuclear generating units with a combined capability of 2,540 MW were placed in commercial operation in southwestern Arizona. The third Palo Verde unit (1,270 MW) is expected to be placed in commercial operation during the third quarter of 1987. The AZ-NM area's share of the Palo Verde nuclear plant represents approximately 60% of the area's planned net generating capacity additions over the next 10 years. The AZ-NM area utilities continue to forecast generating capacity levels which are significantly greater than their minimum capacity margins. This situation has resulted in an increasing need to market surplus electric energy to neighboring areas in the near-term.

Although the Arizona to California transmission system has been strengthened, the transmission system emanating to the west from the Four Corners area has not. It is anticipated that clockwise loop flow will, as in the past, inhibit power transfers from the Four Corners area power plants to their respective Arizona/California owners. For this reason, the AZ-NM area utilities continue to support WSCC's efforts to develop loop flow control procedures as well as long-range plans to reduce the impact of loop flow.

With the continuing economic incentives for California utilities to maximize Pacific Northwest and Southwest imports, the use of sophisticated remedial action schemes such as generator tripping and controlled system islanding are being expanded. Should these remedial action schemes fail to operate as planned, the adverse effect on the AZ-NM area is a matter of serious concern. The AZ-NM utilities are actively working with California utilities, both directly and through WSCC, to increase the assurance that the present and proposed remedial action schemes will not degrade system reliability in the AZ-NM area.

California-Southern Nevada Power Area

The California-Southern Nevada Power Area encompasses California, southern Nevada and the northern portion of Baja California, Mexico.

The accompanying table presents this year's forecast of summer peak demand and energy for the U.S. portion of the area as compared to last year's forecast. Generating capacity margins during summer peak will decrease from 25% to 20% over the next 10 years but will be adequate to supply projected loads.

California-Southern Nevada Power Area (U.S.) Comparison of Forecasts		
	This Year's Forecast (1987-1996)	Last Year's Forecast (1986-1995)
10-Year Forecasts:		
Summer Peak Demand Growth Rate (%/yr)	2.1%	2.1%
Annual Energy Growth Rate (%/yr)	2.0%	2.2%
Forecasts for Year 1995:		
Summer Peak Demand—GWh	50,479	50,961
% Change	-1.0%	
Annual Energy—GWh	252,628	260,183
% Change	-2.9%	

The 913 MW Rancho Seco unit, which has been shut down since December 26, 1985, is scheduled to return to service by the first quarter of 1988. During 1986, over 894 MW of non-utility generation were placed in operation bringing the area total NUG capacity to 3,829 MW.

Over the next ten years, a number of interrelated factors will affect overall system reliability in the California-Southern Nevada Power Area. These factors include the following:

- Remedial action schemes will continue to be used to support existing or increased power transfers.
- In order to provide reliable operation, special operating limits are being observed.
- Phase-shifting transformers scheduled for installation in Colorado and under consideration in the Utah to Arizona/New Mexico interface could have a significant effect upon the California/Southern Nevada systems.
- A number of projects which will result in increased energy transfer capability into the California/Southern Nevada area are:
  - Increasing the ac Pacific Intertie transfer capability
  - Increasing the Arizona-California transfer capability
  - Completion of the Intermountain Power Project
  - Addition of the second Palo Verde-Devers 500 kV transmission line
  - Expansion of the dc Pacific Intertie
  - Completion of the California/Oregon Transmission Project (third ac Pacific Intertie line)
  - Addition of the Mead-Adelanto dc transmission line

These factors and others, as mentioned under the various individual area headings, illustrate the necessity for continual coordination of planning and operation to achieve an acceptable level of interconnected systems reliability. The members of WSCC, through their coordinated efforts, are achieving this objective.

Western Systems Coordinating Council (WSCC), with 60 member systems and 4 affiliates, encompasses approximately 1.8 million square miles of territory in 14 western states plus parts of 2 Canadian provinces and the northern portion of Baja California, Mexico. The Region is characterized by extremes in population and load densities in addition to long distances between load centers and electric power generation sources. The Region is subdivided into 4 areas, namely: the Northwest Power Pool Area, which is winter peaking and heavily dependent on hydro generation; the Rocky Mountain Power Area, which is either summer or winter peaking with a 24% hydro and 62% coal-fired generation mix; the Arizona-New Mexico Power Area, which is summer peaking with a 30% gas/oil and 50% coal-fired generation mix; and the California-Southern Nevada Power Area, which is summer peaking and heavily dependent on gas- and oil-fired generation.

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